THE GROWTH OF WIND ENERGY IN EUROPE: THE EFFECTS ON THE WHOLESALE ELECTRICITY MARKETS

by

Diogo Maia

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Supervised by:

Susana Maria Almeida da Silva

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SHORT BIOGRAPHY

Diogo António da Silva Maia born on August 19^{th} 1987, in the city of Vila do Conde, in the north of Portugal. He attended public primary and secondary schools in the same city until 2005. In that year, he entered the Faculty of Economics of Porto (FEP), to attend a degree in economics.

Before graduating in economics, he joined Caixa Económica Montepio Geral in 2009, where he worked for a year and a half.

In 2012, he graduates in economics and begins working for Yokohama Ibéria in the management and marketing departments, where he continues to work to date. In the same year he enrolled in the Master in Environmental Economics and Management at FEP, which plans to finish with the presentation of this dissertation.

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To my friends, I want to show my deepest appreciation. Your encouragement and faith in me always give me the will to move forward.

To my family who always supported me and my dreams, to you I owe everything that I am. I will always be profoundly grateful.

ABSTRACT

In the EU (European Union – 28 member states), installed wind power capacity more than quadrupled from 2001 to 2011. Its growth owes a great deal to the support that states have given, in the form of subsidies and other incentives. The feed-in tariff has been the most used form to encourage wind power and other renewable sources.

We analyze the 4 countries with the highest wind penetration in 2012 (Denmark, Spain, Portugal and Ireland). The purpose of this work is to study the impact of the growth of the wind farms in the electricity prices in the wholesale markets in these European countries. Because of the low marginal cost of wind energy, the wholesale prices of electricity can be negatively affected. Using daily data from these markets, between January of 2010 and December of 2013, we find that wind power negatively affect the wholesale electricity price of the 4 countries, due to the merit order effect. Furthermore, we show that this impact is different in each country analyzed, due to their market conditions and their electricity generation mix.

Keywords: Wind Energy; Electricity Price; Feed-in Tariff.

RESUMO

Na UE (União Europeia - 28 Estados membros), a capacidade instalada de energia eólica mais que quadruplicou entre 2001 e 2011 e o seu crescimento deve-se, em grande parte, ao apoio que os Estados têm dado, na forma de subsídios e outros incentivos. A tarifa *feed-in* tem sido a forma mais utilizada para incentivar a energia eólica e outras fontes renováveis.

Analisamos os quatro países com maior penetração de energia eólica em 2012 (Dinamarca, Espanha, Portugal e Irlanda). O objetivo deste trabalho é estudar o impacto do crescimento dos parques eólicos nos preços da electricidade nos mercados grossistas destes países europeus. Devido ao baixo custo marginal da energia eólica, os preços da electricidade nos mercados grossistas podem ser afetados negativamente. Com dados diários de Janeiro de 2010 a Dezembro de 2013, verificamos que a energia eólica afeta negativamente o preço da electricidade nos mercados grossistas dos quatro países, devido ao efeito de ordem de mérito. Além disso, mostramos que esse impacto é diferente em cada país analisado, devido às diferentes condições dos mercados e às diversas combinações de fontes para geração de eletricidade.

Palavras-chave: Energia Eólica; Preço da Eletricidade; Tarifa *Feed-In*.

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LIST OF ABBREVIATIONS

CHP	Combined Heat and Power
ERCOT	Electric Reliability Council of Texas
EU	European Union
EU-15	European Union – 15 countries
EUA	European Emission Allowances
MIBEL	Iberian Electricity Market
OMIE	Iberian Market Operator
RES	Renewable Energy Sources
SEM	Single Electricity Market (Ireland and Northern Ireland)
SEMO	Single Electricity Market Operator
TSO	Transmission System Operator
USA	United States of America

1. INTRODUCTION

Electricity production is the major cause of CO_2 emissions (Eurostat, 2013) and that is due to the use of conventional sources such as coal and other fossil fuel sources. Because of that, in Europe, since the nineties (European Commission, 1997) renewable energy sources (RES) have been increasingly important. Wind energy, one of the most significant RES, has the highest growth in the XXI century, and is now the second most important source of renewable energy to generate electricity in the EU, right after hydro (Eurostat, 2014).

Wind energy uses a free fuel but an intermittent one. The electricity output from wind is therefore not controllable, but with the latest developments, can be foreseen with a few days in advance (Abbad, 2010). Because of the high investment cost and because it was a developing technology, the governments in the EU supported the growth of the wind power with several support mechanisms. The main instruments used in the EU were Feed-in Tariffs (FIT), tradable green energy certificates and also priority in dispatching (Timilsina *et al.*, 2013).

A high wind penetration in the electric system of a country poses a series of challenges. The volatility of wind energy output and their low marginal costs are its key features. The effects on the wholesale prices of electricity can be therefore various. Several authors address this problem (Sáenz de Miera *et al.*, 2008; Forrest and MacGill, 2013; Cutler *et al.*,2011; Woo *et al.*, 2011; 2013) and the concluding remarks seems to be that wind energy can reduce the wholesale prices of electricity, in case of a competitive market, but also increase the spot price variance. However there is little analysis of real daily data in the countries within the EU. Even more, there are no studies comparing these effects in the wholesale prices of countries with high wind penetration and with real data.

In this paper we examine the top 4 countries in EU with the highest wind power penetration in 2012 (Denmark, Portugal, Spain and Ireland). We use real daily data from the electricity wholesale markets, including price, wind power generation and other variables, such the price of natural gas, coal and *brent*, from January 1st of 2010 to December 31st of 2013.

The purpose of this study is to find the effect of the wind power generation on the wholesale price of electricity of these 4 countries of EU, with different electricity markets and energy mixes, presenting comparative conclusions. For that we develop a multiple linear regression model for each daily average spot price of electricity in the wholesale markets of Denmark (Nord Pool Spot), Portugal and Spain (MIBEL) and Ireland (SEM).

We conclude that, indeed, wind power generation reduces the wholesale price of electricity. However, and contrarily to the general notion, more wind power penetration does not necessarily indicate a greater total effect on the spot price of electricity. We find that the total effect of the wind power generation on the electricity price depends on the electricity generation mix of the country and on its integration with other markets.

This dissertation begins addressing the development of wind power in the EU, mainly on Denmark, Portugal, Spain and Ireland (section 2). In Section 3 we review the research already conducted on this topic until today, which includes analysis with real data for other countries. Section 4 describes our methodology and our data. Section 5 analyzes the results of applying the multiple linear regression models to the daily data of the wholesale markets already mentioned and in Section 6 we conclude.

2. THE RISE OF THE WIND ENERGY IN EUROPE

In the last years of the 20th century, the European Union and its institutions settle the parameters for a breakthrough of the so called Renewable Energy Sources (RES). The renewables (which include hydro, wind, biomass and solar energies) were seen as key to respond to various problems. They could help to achieve the goals of the Kyoto protocol, by reducing the emissions from coal and gas plants (Dincer, 2000). Further, they could also have a role in other objectives, such as energy security and independence, by reducing energy imports. Another major and broad economic advantage of the RES is the creation of supply industries and therefore jobs (European Commission, 1997).

With the necessary policies, the European Commission projected in 1997, the total RES could cover 23.5% of the total electric production of the European Union of the first 15 member states (EU-15) in 2010. In 1995 they covered only 14.3%, being the majority generated through hydro energy (13%). In the same year, wind energy only accounted for 0.2% (4 TWh) of the total electric production in the EU-15. The same projection pointed to a total of 80 TWh of electricity produced by wind for 2010 in the EU-15. That would be 20 times the production in the base year of 1995 (European Commission, 1997).

However, the increase in wind energy in Europe was even more substantial. A total of 145 TWh of wind energy was produced in 2010 (EU-15). More than 35 times the production of the base year, 1995. That accounted for almost 7% of the electricity produced in 2010. If we consider the total 28 countries of the EU, the percentage decreases to 6.24% (wind energy in the total production of electricity). The renewable energy represented 19.7% of electricity production in 2010 for the EU-28 and it reached 23.5% in 2012 (Eurostat, 2014).

Figure 1 shows the tremendous growth that wind power had in less than 20 years. There are a total of 8 countries that have more than 10% of electricity consumption generated from wind.

In Figure 1 we can also see which countries rely most on wind energy to produce electricity. The top 4 countries are Denmark, Portugal, Spain, and Ireland. Germany has the largest wind installed capacity, however in relative terms, it falls to sixth place, even behind Lithuania. Therefore, for this thesis we will concentrate on these 4 countries. All these countries are in EU for more than 25 years now, and share the same directives and regulations.

In the following sections we will describe the primary electricity fonts for each of these 4 countries and find the similarities and differences.

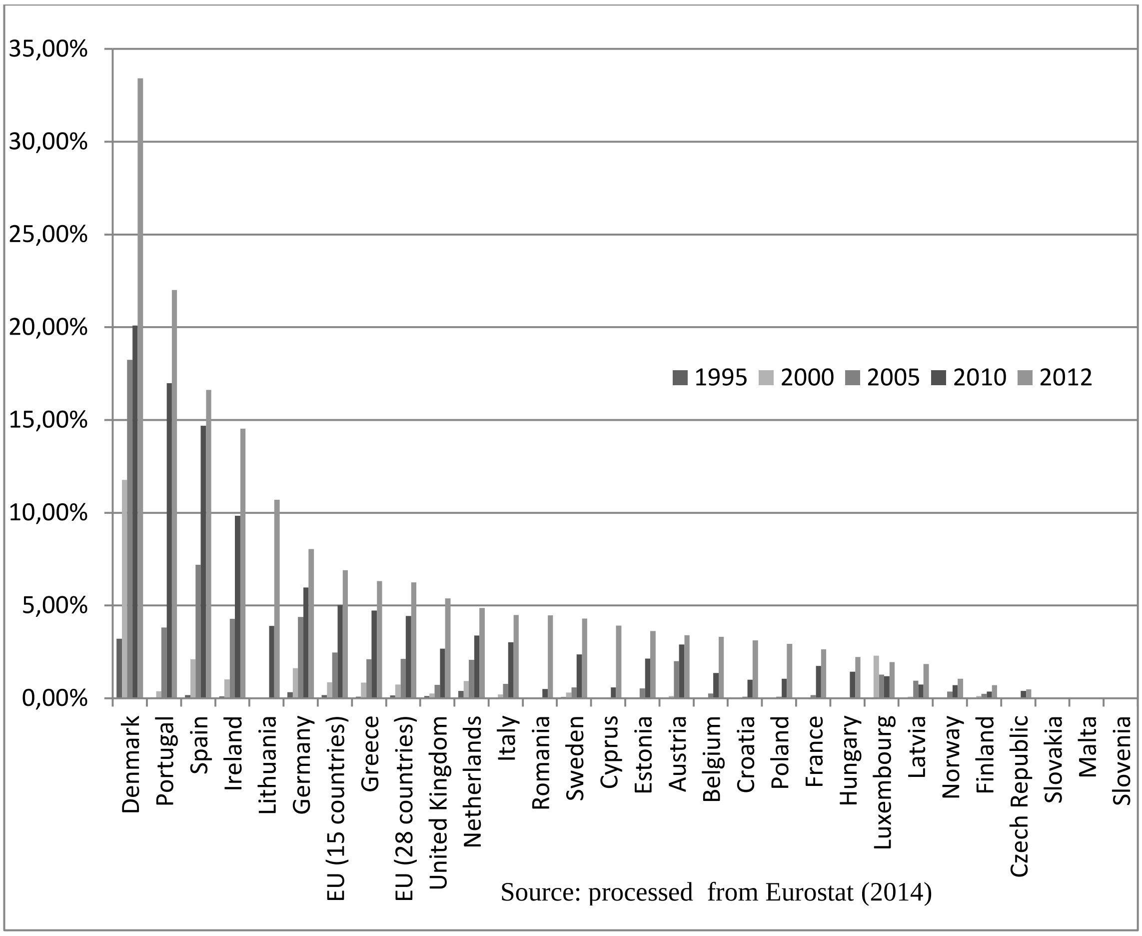


Figure 1 - Wind power penetration on electricity consumption (EU)

2.1.DENMARK

Within Europe, this country was the first to bet on wind power. In 2000 it had almost 2500 MW of installed capacity of wind power. More than Ireland or Greece had in 2012. The installed capacity of wind power grew from 630 MW in 1995 to 4.163 MW in 2012 (Eurostat, 2014).

Figure 2 tells us that, in 2012, 19% of the installed capacity to produce electricity was in the form of wind turbines. That is the third largest primary electricity generation source in Denmark. In that year, one third of all electricity consumed in Denmark was from wind (Figure 1).

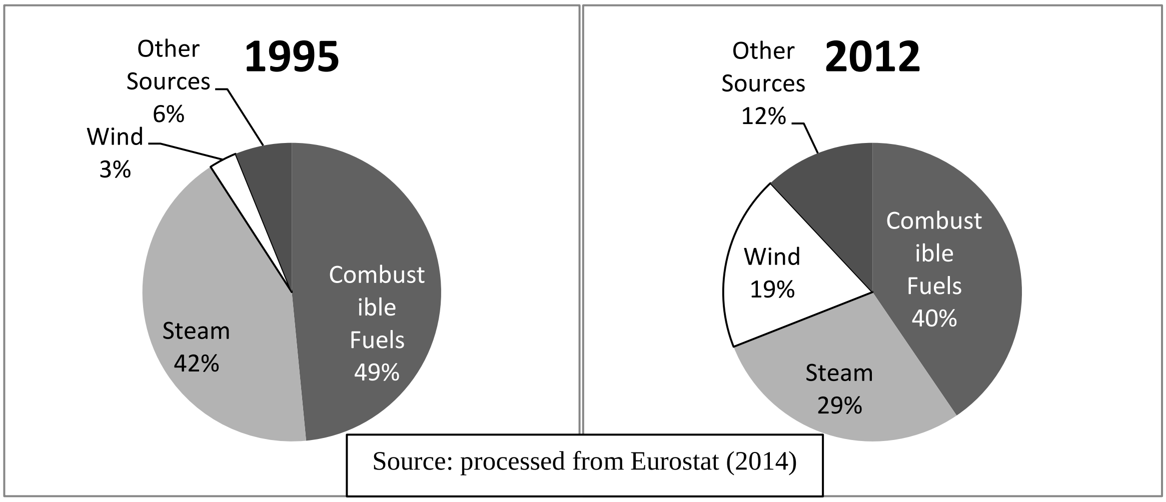


Figure 2 - Installed capacity in Denmark - producers - 1995 and 2012

Perhaps one of the reasons why Denmark has promoted wind power was due to its natural conditions. All European Nordic countries have exceptional conditions for the production of hydroelectricity, except Denmark (Reiche and Bechberger, 2004).

Wind energy is a long term commitment for the governments in Denmark. The windmills have been the target for policymakers since the early 1980´s (Agnolucci, 2007), when the government setup a target of 10% of electricity from wind for 2000. As can be seen in Figure 1, that objective was overcome. In the 80´s the policies to increase wind power were in the form of agreements with the largest utilities for a determined quantified objective (Agnolucci, 2007).

The first offshore wind farm in Denmark began operating in 1991 in the Baltic Sea. Already then, the Danish authorities fostered offshore wind energy as a response to the difficulty of finding good sites on land (Meyer and Koefoed, 2003).

The introduction of the feed-in tariff in 1992 was the ignition for the growth observed in that decade in wind turbines. As pointed out by several authors (Agnolucci, 2007; Meyer, 2004), the feed-in tariff was not an immediate success. Only after 1995 there was a boom in new installations of windmills. Observing Figure 3, we can see that from 1995 to 1998 the installed capacity doubled. The feed-in tariff provided the generators of wind energy with an average pay of around 0,08€ per KWh (Agnolucci, 2007; Meyer, 2004; Munksgaard and Morthorst, 2008).

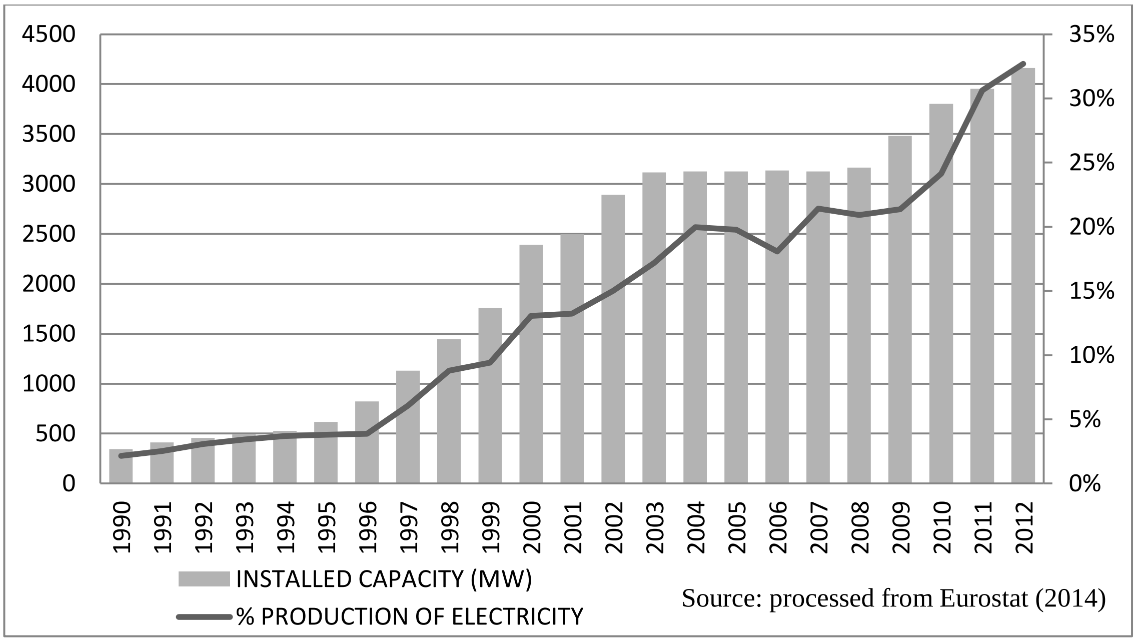


Figure 3 - Installed capacity and percentage of wind energy in electricity consumption in Denmark since 1990

The strong success of the feed-in tariff became its own danger (Agnolucci, 2007). In 1999 the Danish Energy Act introduced in the legislation the Green Certificate Market and a minimum consumer quota of green energy.

The Energy Act also determined the liberalization of the electricity market of Denmark, ahead of the rest of the Europe. In 2003 the market opened to all consumers (Meyer and Koefoed, 2003).

The result was a peak in new installations of windmills in 2000 (as seen in Figure 3), with investor speeding-up to benefit from the old feed-in tariff. The new windmills connected to the grid between 2000 and 2002 benefited from a feed-in tariff of 0,058€/kWh. After 2003, new wind turbines had to sell the energy to the market, and on top of the market price, they gained a subsidy of 0,016€/kWh (for a 20-year period). This is only applied to wind power on land. Offshore windmills gained a feed-in tariff of around 0,07€/kWh for the first 10 years and a subsidy per kWh (0,003€ or 0,016€ depending on the cases) during the next 20 years on top of the market price (Munksgaard and Morthorst, 2008).

As a result of the change in the legislation, from 2003 to 2008 the installed capacity of wind energy did not grow, as can be seen in Figure 3.

In February of 2008 an Energy Agreement for 2008-2011 was approved in Denmark. The agreement improved the subsidies to land wind energy and introduced a new offshore farm of 400 MW (Danish Energy Agency, 2008). The objective of the Danish Authorities was to reach 20% of renewable energy in gross energy consumption by 2011. That objective was achieved.

In 2012 a new and more ambitious plan was designed. The Danish Energy Agreement of March 2012 set a target of 50% for electricity consumption to be supplied by wind power by 2020. A total of 1500 MW of new offshore wind energy is due until 2020 and a plan to foster 500 MW of onshore was introduced (Ministry of Climate, 2012).

As can be seen in Figure 3, in the last years the installed capacity of wind power in Denmark grew. From 2008 to 2012 more 1000 MW of wind turbines were installed.

2.2. SPAIN

In 1995 Spain had almost none windmills in its landscape. More than 15 years later, in 2012, it had the second largest wind energy output of Europe (Germany was the leading generator of wind energy). In that year, almost one quarter of the Spanish electricity generation installed capacity was in wind power (Figure 4). Wind energy output was about 20% of the total of electricity consumed (Figure 5).

As can be seen in Figure 4, wind power became the first RES in Spain, surpassing hydro energy which had a small growth in the last years. In fact, the total installed capacity grew more than 50% from 1995 to 2012 while hydro energy grew 12% in the same period. For comparison, the installed capacity of wind energy in 2012 is more than 200 times the value of what was in 1995.

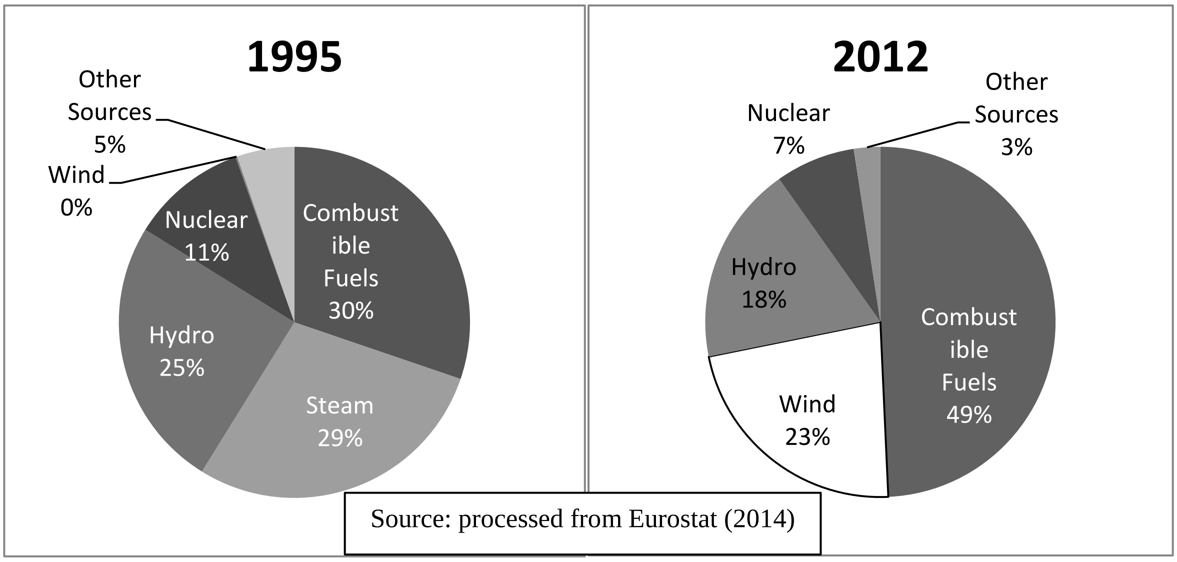


Figure 4 - Installed capacity in Spain- producers - 1995 and 2012

Figure 5 shows that it was only after 1998 that Spain began to experience a strong growth in wind energy. In the same year the RD 2818/1998 introduced the feed-in tariff in the Spanish legislation. However a unique feature was introduced: two options, a fixed tariff or a fixed premium.

The wind energy producer had two options: sell the energy to the distributor at a fixed tariff of 0,0662 €/kWh; or sell the energy in the market and receive a premium of

0,0316 €/kWh on top of the market price. Those were the tariffs establish for 1999 for wind energy (Abbad, 2010; del Río González, 2008; Sáenz de Miera *et al.*, 2008).

The option for a feed-in tariff was consensual in the country and was based on the efforts done in the past years in Denmark and Germany. The fixed premium was an innovation in the European framework. That was set to encourage the wind producers to enter the wholesale market of electricity (del Río González, 2008).

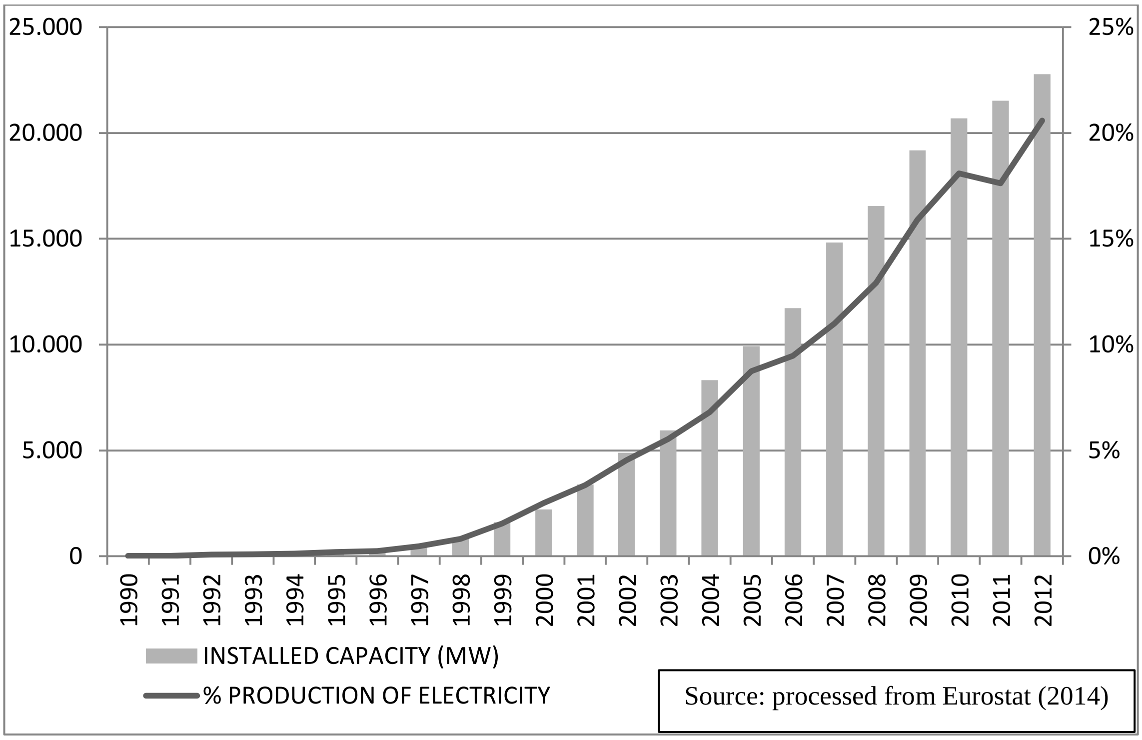


Figure 5 - Installed capacity and percentage of wind energy in electricity consumption in Spain since 1990

The effect of the RD 2818/1998 was immediate. In 2004, Spain had 10 times the installed capacity of wind energy of 1998 and 7% of electricity coming from the wind (Figure 5).

In 2004, the Spanish authorities, in response to the enormous growth of RES, especially wind energy, reformed the system with the RD 436/2004. The reform tackled some concerns of the key stakeholders. The feed-in tariff, which previously was determined by the state annually, became tied with the average electricity price. That resulted in an increase in the fixed tariff and in the fixed premium (del Río González, 2008). More than 90% of producers switched to the fixed premium option, because of the increase in the wholesale prices in that period (Abbad, 2010).

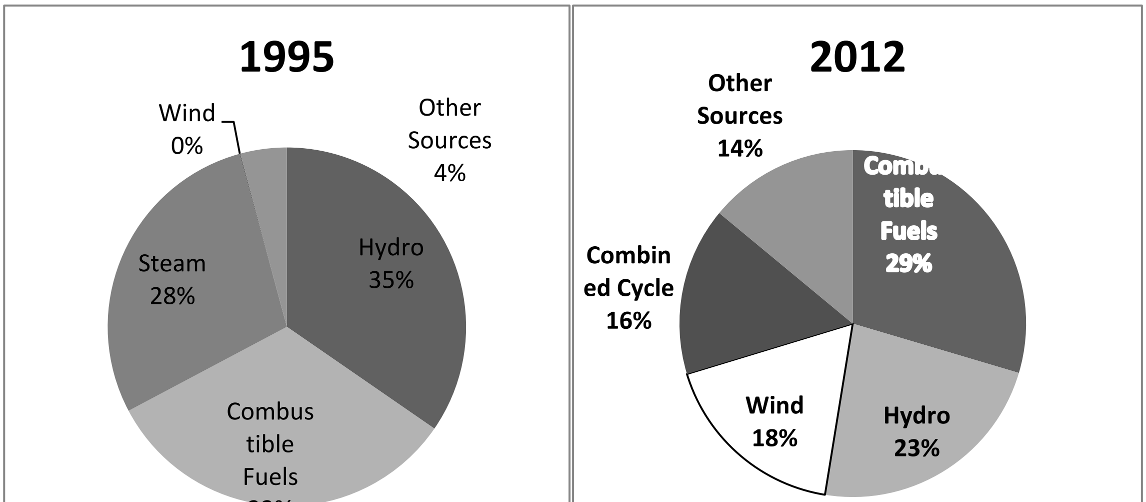
Another reform of the system occurred in 2007 with the RD 661/2007. The main differentiation was the introduction of a cap and a floor for the income of producers that participated in the market. Thereby the owners of onshore windmills that sold the energy in the market would receive the market price with an upper limit (0,085 €/kWh) and a lower limit (0,071 €/kWh). This was introduced to secure the return on investments in RES (floor) and also to limit their profits (cap) (Abbad, 2010; del Río González, 2008).

The innovative incentive on RES resulted in the continuous growth of wind energy installations and production from 2005 to 2012 (Figure 5). That was also a result of the increasing price of electricity in the wholesale market of the Iberian Peninsula.

2.3. PORTUGAL

Portugal, like Spain, had almost no wind power in 1995. Figure 6 shows that hydro energy and combustible fuels were, in that year, the major primary sources to generate electricity. In 2012, although still relaying almost one third in combustible fuel sources, wind energy represented 18% of the total installed capacity to produce electricity.

Because of the priority given to the dispatch of RES, wind energy accounted for 22% of all electricity consumed in 2012, second only to Denmark in Europe (see Figure 1).



Source: processed from Eurostat (2014)

Figure 6 - Installed capacity in Portugal - producers - 1995 and 2012

As shown in Figure 7, it was only in the beginning of the 21th century that wind energy started to take off in Portugal. In 2001 only 1% of the generated electricity came from wind power. That resulted from only 125 MW of installed capacity.

Like Spain and Denmark, Portugal used the feed-in tariff to increase electricity generation from RES. But unlike Spain, this country only offered one option for the producers: sell their energy to last resort supplier at a state guaranteed price (Amorim *et al.*, 2013; Pereira and Saraiva, 2013).

The average feed-in tariff for wind power grew from 0,06 €/kWh in 2000-2001, to around 0,08 €/kWh in 2002 and even more in 2005 (around 0,09 €kWh) (Amorim *et al.*, 2013). That growth in the earnings for wind energy producers generated a tremendous increase in new windmills. From 2004 to 2005 the installed capacity almost doubled (553 MW to 1064 MW).

After 2005, the average feed-in tariff remained in around 0,09 €/kWh (Amorim *et al.*, 2013). The stable framework provided investors the right incentive to invest in wind.

As pointed out by Amorim *et al.* (2013) 82% of the total installed capacity to produce electricity in Portugal had in the end of 2010 a state guaranteed price, and that will not change until 2020. All wind energy in Portugal benefited from the state guarantee and that will be maintained in the next years.

In 2012, the Portuguese government ceased the attribution of permits for new windmills, by the DL 25/2012 of 06 of February. It was the end of the vigorous growth of wind energy that can be seen in Figure 7: the increase of installed capacity from 2011 to 2012 is the smaller since 2003.

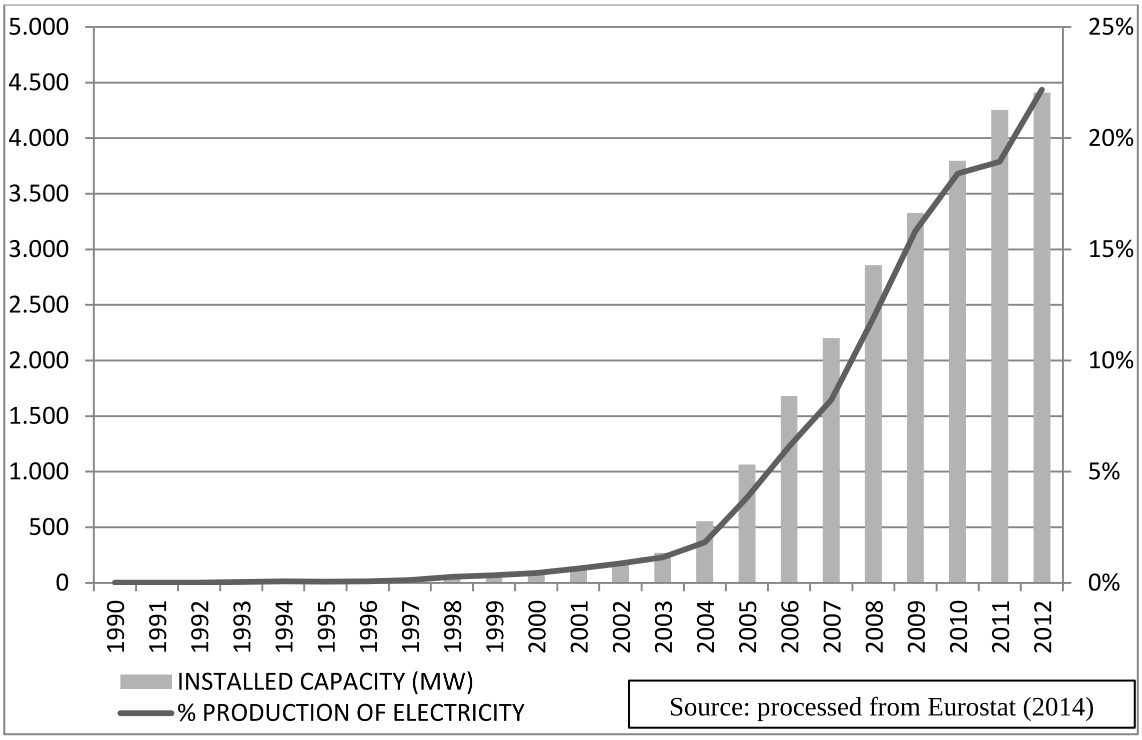


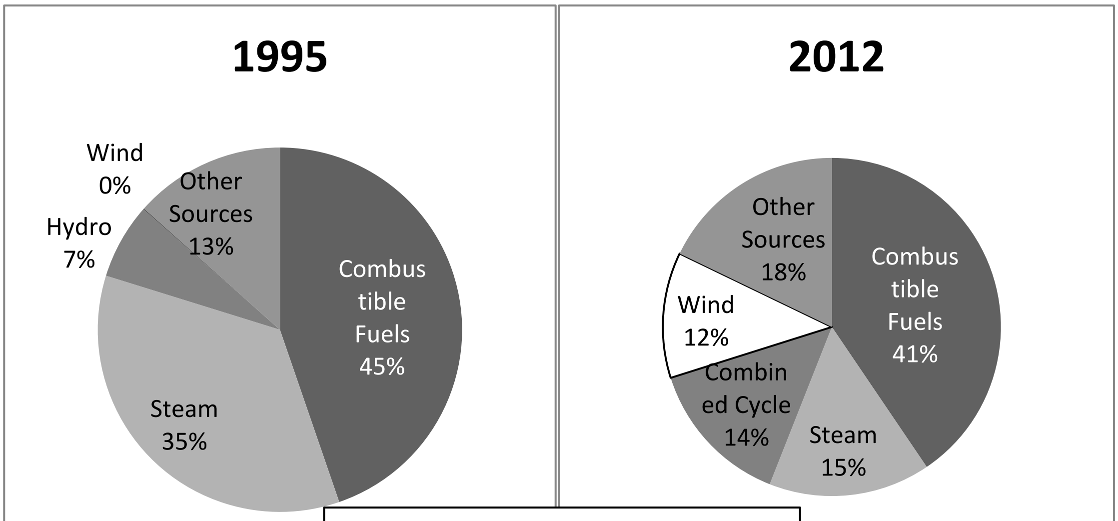
Figure 7 - Installed capacity and percentage of wind energy in electricity consumption in Portugal since 1990

2.4. IRELAND

Of the four countries analyzed, Ireland had the lowest installed wind power capacity, and as expected, the country that produced less wind power in 2012, both in absolute and relative terms (Eurostat, 2014). Only 12% of the total installed capacity to produce electricity is wind energy (see Figure 8).

This is a country that relies heavily on fossil fuels to generated electricity. If we add the installed capacities of combustible fuels (that include oil and coal) and combined cycle (natural gas) we reach 55% for 2012 (see Figure 8).

Wind energy had only 6 MW of installed capacity in 1995. And in 2012 it reached more than 1750 MW (Figure 9).



Source: processed from Eurostat (2014)

Figure 8 - Installed capacity in Ireland - producers - 1995 and 2012

Public wind energy support began in 1993 in Ireland with the alternative energy requirement (AER), which fostered investment through competitive tender, granting the winning bidders a 15 year power purchase agreement with the public electricity supplier. That scheme supported over 500 MW until 2007 (Foley *et al.*, 2013).

In 2006, it was introduced the first renewable energy feed-in tariff (REFIT) in Ireland. The first REFIT was a 15 year support scheme that pretended to increase by 400 MW the renewable installed capacity to produce electricity, until 2010. It was also an original design, because it was composed of 3 parts (Doherty and O'Malley, 2011)

- a fixed part called "balancing payment element", equal to all RES (0,00855 €/kWh in 2006);
- the "floor price element": 0.057 €/kWh in 2006 - Wind producers would receive at least this value for the energy produced, but they could get more if the price in the wholesale market was higher. It is therefore a minimum reference price;
- and the "technology difference element". Equal to 0€ /kWh to large wind (> 5MW) and 0,002 €/kWh to small wind (< 5MW), in 2006.

Thus a large wind project would receive a minimum of 0,06555 €/kWh in 2006. A small wind project would receive a minimum of 0,06755 €/kWh, in the same year. All the 3 parts were adjusted yearly for inflation (Devitt and Valeri, 2011).

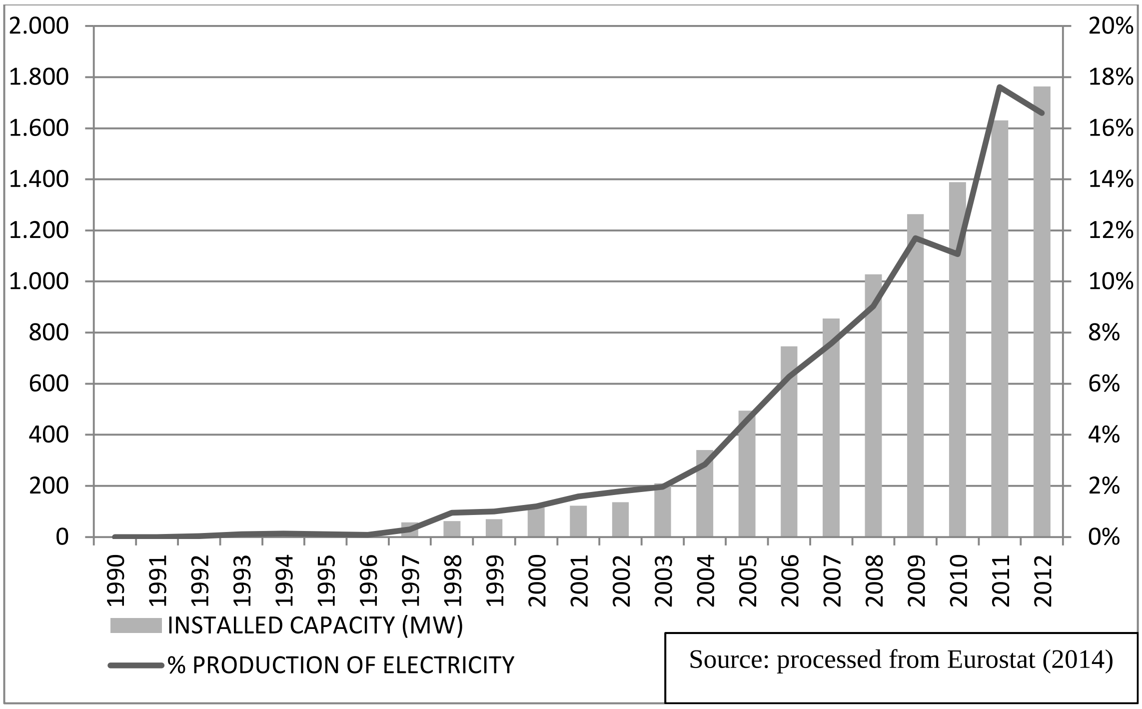


Figure 9 - Installed Capacity and percentage of wind energy in electricity consumption in Ireland since 1990

Figure 9 shows that in 2006, wind installed capacity grew more than 50%, from 494 MW in 2005, to 746 MW in the next year.

In 2009 the REFIT was reformed and additional RES were added to the scheme. For example, off-shore wind was supported by a total of 0,14995 €/kWh for 2010. In that year the large on-shore wind energy received a minimum of 0,0763 €/kWh (Devitt and Valeri, 2011).

The result of the REFIT has been a continuous growth of wind installed capacity and also of wind power production (except for 2010 and 2012). We expect to continue observing this growth, since RES should provide 16 per cent of total energy demand by 2020, according to the target set by the Irish government. For that, about 40% or electricity should come from RES. And the majority of that should be wind (Devitt and Valeri, 2011).

3. WIND ENERGY AND THE WHOLESALE MARKETS

The spot (day-ahead) price of electricity in the wholesale market is influenced by several variables. This is a market where the companies trade the electricity for the next day, with different biddings for all the hours of the next day (EWEA, 2010). The price formation, like any price in an economy, is determined by the supply and demand. In the supply side there are numerous technologies that produce electricity: the more traditional thermal plants, nuclear plants and the RES (wind energy, solar energy among others). Their given price and availability at a certain hour will form the supply curve of electricity (Sáenz de Miera *et al.*, 2008). The need for electricity in an economy, for the industries, the services and the households will form the demand. Usually the demand for electricity is very inelastic in the short term (Forrest and MacGill, 2013) given that final consumers do not receive the wholesale market price signals.

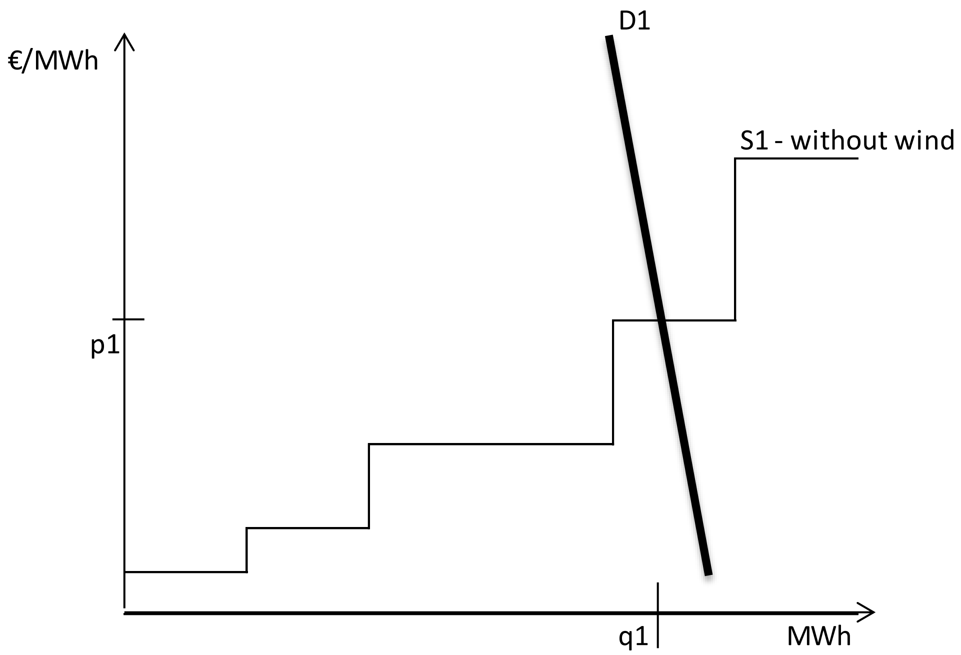


Figure 10 - Supply and demand curve of electricity in a spot market (own elaboration)

In figure 10 we can visualize a fictional market with their respective supply (S1) and demand (D1) curves. In the left of the supply curve, we find the technologies with the lower marginal costs. Following the curve to the right, the price grows with the introduction in the market of more costly plants. Nuclear, coal plants and the RES usually set the lowest prices in the supply curve, becoming the base load plants. Other plants like natural gas plants and fuel plants are normally the peak load plants (Sáenz de Miera *et al.*, 2008). That said, we can easily conclude that within hours of low demand, the demand curve shifts to the left and the base load plants set the marginal price. When the demand is high, the demand curve goes to the right and the peak load plants, like natural gas plants, determines the marginal price, the price in the wholesale market for all the power purchased.

Wind power has a characteristic that differentiates it from all the other sources: its fuel, the wind, is free. However, this comes with a “price”, the variability and unpredictability of that fuel. This has become less of a problem with the capacities developed by the wind utilities to forecast the wind in the next 2 to 3 days (Abbad, 2010). Therefore, wind power has low marginal costs (Sáenz de Miera *et al.*, 2008; Forrest and MacGill, 2013; Cutler *et al.*, 2011; Woo *et al.*, 2011).

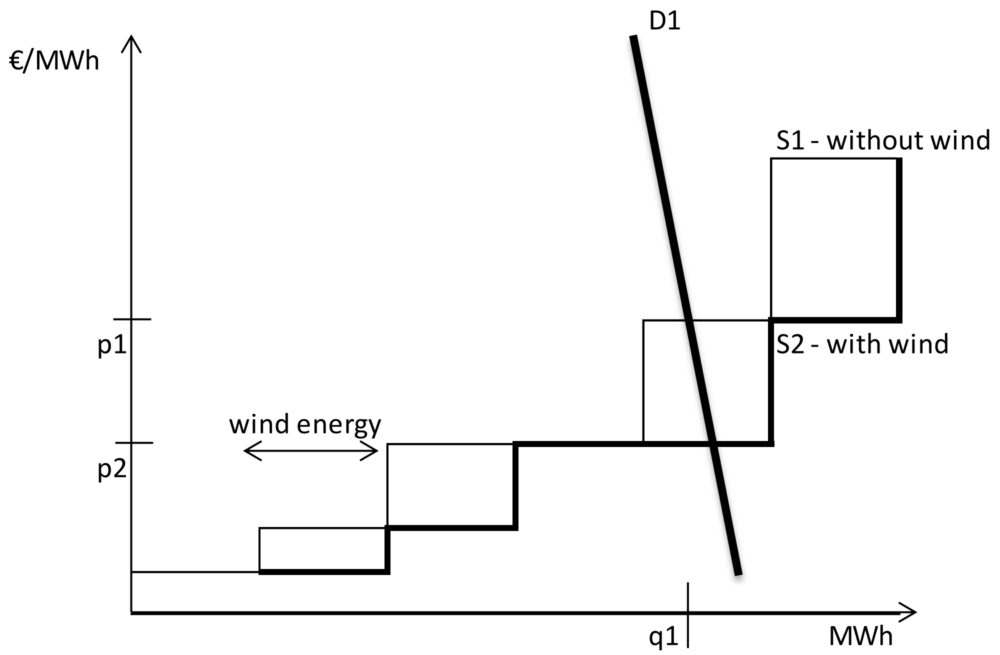


Figure 11 - Introduction of wind in the supply curve of electricity in a spot market (own elaboration)

The direct effect of the wind power in the spot price can be described by the following, (depending if the wind power companies participate on the market or if it has to be dispatched preferentially):

- In a wholesale market where the wind power is treated like any other technology, because of their low marginal cost, it replaces other plants with higher marginal costs, and the marginal price is set at a lower value (Forrest and MacGill, 2013). In figure 11 we can see that p2 (price with wind power) is lower that p1 (supply curve without wind power);
- In a market where the wind energy does not enter the bidding process, i. e., the system operator is obligated to buy all the wind energy output (like in the Portuguese wholesale market until 2013), the wind energy will reduce the demand for other electricity sources like thermal plants, reducing the price in the market (Sáenz de Miera *et al.*, 2008; Sensfuß *et al.*, 2008). With less demand (D2) the price in the wholesale market drops to p2 – see figure 12.

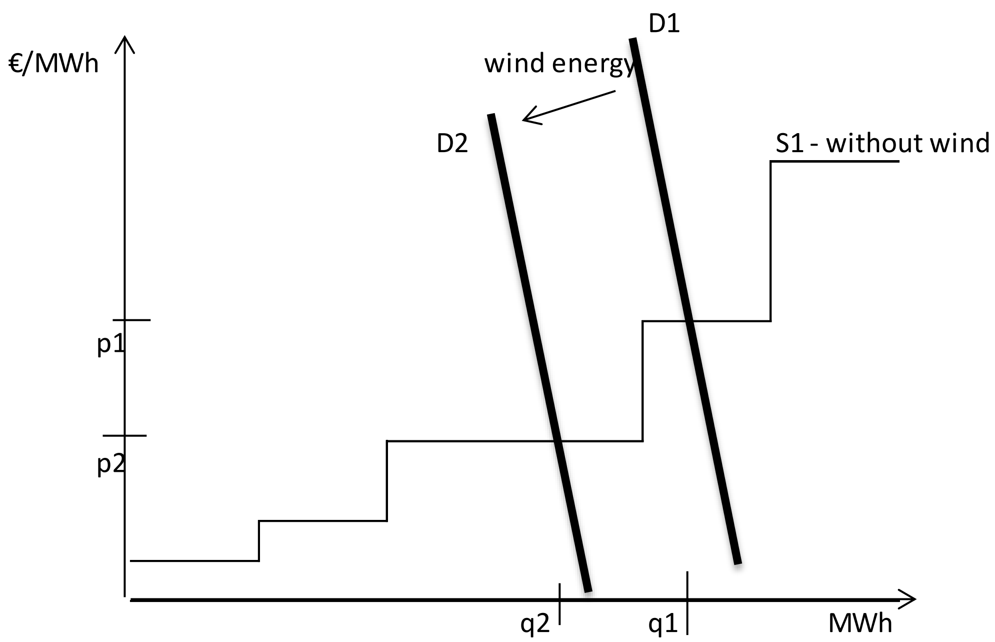


Figure 12 - Introduction of wind in the demand curve of electricity in a spot market (own elaboration)

In the two cases, whatever the treatment that the market gives to wind power, in theory, the result will be the same, a reduction in the wholesale price to p2.

In addition to the direct effect, wind energy has a second and indirect effect. Because of their residual CO_2 emissions, wind energy is a green energy. Thus, increasing wind energy output will decrease the demand for emission certificates. The reduction in the demand will create a drop in the price of certificates, reducing that cost for all the electricity producers. Therefore, the marginal cost for all the thermal plants will decrease and that gives an opportunity to lower bidding in the wholesale market (Sáenz de Miera *et al.*, 2008).

It is necessary to note that this effect in the wholesale price could not result in savings for the final consumer. In an economy where the wind energy is supported by a feed-in tariff, only if the total costs with the subsidies are lower than the total savings provided by the decrease of the spot price, will the final consumers benefit from a lower electricity price. As can be seen in figure 13, the savings in the wholesale market are the total underline area. The merit order effect is obtained because of the decline of the price for all the energy traded. The market value of wind is, literally, the price of the electricity in the market versus the wind power produced at that time. Thus, if the total cost with the feed-in tariff is not equal or larger than the value of the savings (the merit order effect and the market value of wind) the system will profit from the support of wind power (Azofra *et al.*, 2014, Sensfuß *et al.*, 2008).

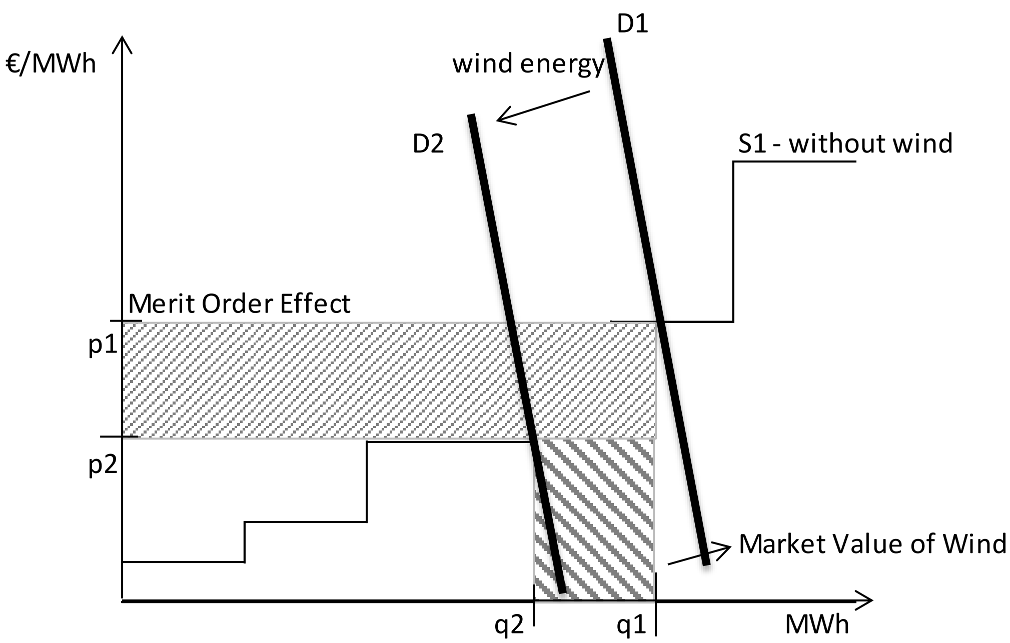


Figure 13 - Savings in the wholesale market with a presence of wind energy (own elaboration)

Sensfuß *et al.* (2008) conducts a study for the Germany wholesale market for 2006. The authors concludes that the total savings with the effect of wind energy and others RES in the spot price (decreasing the wholesale price in 7,83€/MWh, around 7,5 billion € in total) compensates the total costs of supporting this technologies (5,6 billion €) for 2006. That said, the consumers had a net profit with the feed-in tariffs if the savings were passed to them by the consumer market.

Sáenz de Miera *et al.* (2008) also finds a negative correlation between the wind power output and the wholesale price of electricity for 2006 in the Spanish market. Simulating the direct effect of the wind energy, the authors conclude that wind energy was responsible for a decrease of the wholesale price of electricity of 7,08€/Mwh in 2005 and 4,75€/MWh in 2006. With that results, the article concludes that there were a total of net savings of around 1.250 M€ for 2005 and 2006 in Spain with the incentives for the wind energy.

Similar results are found by Azofra *et al.* (2014) for Spain in 2012. The authors show that above 83% of the real wind production of 2012, all the levels of wind production would create a surplus in the system (total savings higher than costs with incentives). Regarding the real data, the authors conclude that wind energy contribute to decrease the wholesale price by around 9€/MWh.

Regarding Spain, however, a different conclusion is achieved by Ciarreta *et al.* (2014). In their paper, the authors combine all technologies that are supported by the government with feed-in tariffs (RES and cogeneration). The authors defend that a turning point was reached in 2010, when the net savings with the incentives became negative. For 2011 and 2012 the net costs with the incentives reached around 3.300 million € (each year), estimate the authors. Therefore, the paper concludes that the Spanish had to change the incentives regulation, as they did in the end of 2013.

Munksgaard and Morthorst (2008) also show for Denmark the negative effect of the wind energy in the wholesale price in the Nord Pool. The authors conclude that reduction of the price was passed to the final consumer in 2004, 2005 and 2006.

Outside Europe there are some authors contributing for this literature. Woo *et al.* (2011) analyze the impact of wind energy in the Texas wholesale electricity market – the larger consumer of electricity in the United States of America (USA). The article uses real data from the Electric Reliability Council of Texas (ERCOT) – the electric system operator – from January, 2007 to May of 2010. The data consists of observations for the 15 minutes market price, the zonal loads and wind and nuclear production. The authors develop a model to explain the price which is the dependent variable. The independent variables are the wind generation, nuclear generation, the price of natural gas in the Henry Hub, the electricity loads, the lagged price – i.e., the price in the market in the last period – and binary variables accounting for the month, day of week and hour of the day. Applying the maximum likelihood method to the previous stated model they conclude that wind generation decreases the price in all the zonal markets in Texas.

The authors find the same negative relation between the nuclear production and the market price and also a positive effect of the price of natural gas on the wholesale market price.

Woo *et al.* (2013) does a similar study for the USA States of Oregon and Washington – the Pacific Northwest. These are particularly rich areas of hydro production. The authors show that, in that context, wind energy still reduces the wholesale price of electricity, even more if the natural gas plants are the ones setting the market price. However the effect is smaller than the one in the State of Texas (previous presented). That is because Texas bases their electricity generation on thermal plants, in contrast with the hydro-based Pacific Northwest. Nevertheless wind power has a role in the electric system of such economies, providing a diverse generation mix, important in case of droughts.

Forrest and MacGill (2013) examine the impact of wind electricity generation in the spot price of the wholesale market in Australia, as well as its effect on other energy sources, particularly in coal and natural gas plants. The Australian market has seen in recent years an increase in wind energy (Cutler *et al.*, 2011) due to state support to this energy (MacGill *et al.*, 2006).

Forrest and MacGill (2013) apply a model in which the dependent variable is the logarithm of the wholesale price in the electricity market. The dependent variables are the wind generation, the price lagged one period (also in logarithm), the market demand, and binary variables to control for seasonality. With a sample of the 30 minute market period from Mar-2009 to Feb-2011, the model is estimated using the ordinary least square method. As in (Woo *et al.* (2011), Woo *et al.*, 2013) wind output has an negative estimated coefficient. This proves that an increase in wind power production decreases the level of prices in the wholesale market. The article also studies the effect of wind energy production in coal and natural gas plants. An increase in the production of wind power had a significant negative effect on the production of natural gas plants and a lower negative effect on the output of coal plants.

Natural gas plants are usually the ones setting the price in the wholesale market, because their relative high marginal cost (Emery and Liu, 2002). Because of that Nakajima and Hamori (2013) find a high causal relationship between the Henry Hub natural gas price and the wholesale price of electricity in the Southeast States of the USA for the period from January, 2005 to December, 2009.

In an electric system, the increase wind energy generation typically displaces more costly thermal plants like natural gas plants, setting the price in an competitive wholesale market at a lower level (Forrest and MacGill, 2013; Sáenz de Miera *et al.*, 2008; Woo *et al.*, 2011; Woo *et al.*, 2013).

4. METHODOLOGY

In this section we describe the steps taken to analyze the effect of wind energy in the wholesale markets of the four countries already presented in chapter 2: Denmark, Spain, Portugal and Ireland. We conducted an individual analysis of the determinants of each spot price in the electricity wholesale market of the four countries.

This section is arranged as follows:

- 4.1 Data: Here we introduce the data used in our analysis: the prices in the electricity wholesale markets, the prices of commodities, the most important stock index for each country and the electricity generation data;
- 4.2 The Model: We show and explain the chosen models to evaluate the effect of wind in the wholesale prices of electricity.

Following, in chapter 5, we analyze the results of the adjustments for all the spot prices, comparing them with the expected outcomes. We proceed taking comparative remarks between the 4 countries.

4.1. DATA

In this chapter we present the variables and the data chosen to proceed with our analysis of the impact of wind energy in the wholesale prices of electricity. In this study we use data from the 4 countries: Denmark, Spain, Portugal and Ireland. These countries were elected, as said in chapter 2, because they are in Europe, the ones with higher wind power penetration in the electricity markets, in 2012.

The sample period is between January 1st of 2010 and December 31st of 2013, and the periodicity of the variables is daily, so we have 1461 observations for each variable.

We selected this period because it contains a large amount of observations, eliminating the possibility of a biased analysis. With this we have a closed 4 years sample (2010, 2011, 2012 and 2013). The periodicity of the data was selected based on the availability of data for all the countries, given that we wanted the possibility of comparison.

First, we must present the wholesale markets of these 4 countries and the spot prices that we analyze. The spot prices of electricity are the variables to be explained in our study. Because we have 5 spot prices of electricity (as we show in 4.1.1.) we construct 5 similar models to explain their variations (see 4.2.). We do the analysis for each price separately to have results for each country and to compare them.

Following, we present the independent variables we use to explain the electricity price: the commodities and emissions prices (4.1.2.); the stock exchanges indexes (4.1.3.); and the electricity generation data for each country (4.1.4.). Their importance to explain the spot price of electricity is specified in each point.

4.1.1. THE WHOLESALE MARKETS AND THE SPOT PRICES OF ELECTRICITY

We analyze 4 countries, but because Portugal and Spain share the same market, we have in our study only 3 wholesale markets.

The wholesale electricity markets have day-ahead auctions, intra-day trading and other operations for the balance of the electric system. We focus on the day-ahead market prices, because it is here that almost all the energy in the market is traded (European Commission, 2012).

Denmark participates in the Nord Pool Spot market since 2000. This market joins today Norway, Sweden, Finland, Estonia, Latvia, Lithuania and Denmark. As can be seen in figure 14, the market is divided into different areas. For example, Denmark is divided into DK1 (west) and DK2 (east). Only Finland, Estonia, Latvia and Lithuania are not divided. In the Nord Pool Spot day-ahead market (Elspot), a single price (system price) is obtained with the demand and supply of all the countries. Figure 14 shows that, for the day 10 of September, 2013, the system price was 41,67€/MWh. After that, the connection limits are taken into account, resulting in different prices for the various zones. For this very reason, we have different prices for DK1 and DK2.

The continental Denmark, the bigger area (DK1), has power trade with DK2, Germany, Norway and Sweden. DK2 has the same connections, except with Norway.

Portugal and Spain share a joined market for electricity, the Iberian Electricity Market (MIBEL). The transactions in the MIBEL began in July of 2007. Like in the Nord Pool Spot day-ahead market, a single price is obtained with the demand and supply of Portugal and Spain. After that, the connection limits are taken into account, which may result in different prices for Portugal and Spain. Figure 16 shows the high-voltage interconnections between the two countries.

The day-ahead market is operated by the Iberian Market Operator (OMIE).

Figure 14 - Nord Pool Spot market map – spot prices in September, 10th of 2013. Map available at http://www.nordpoolspot.com/ (retrieved at 19/09/2014).

Figure 15 - Electric interconnections between Portugal and Spain in 2013 (REN, 2014)

Ireland participates with Northern Ireland in the Single Electricity Market (SEM). This market, created in 2005, joins the demand and supply of both areas of the island to determinate a single price. The SEM Operator (SEMO) regulates and controls the markets operations and the energy flows between the Northern Ireland and Ireland. Figure 15 shows the grid connections between the two areas.

Figure 16 - Ireland grid connections with Northern Ireland – Map available at http://www.soni.ltd.uk/ (retrieved at 13/09/2014)

Following, we present the wholesale prices of electricity for these countries in the day-ahead auctions:

- **$DK1\_PRICE_t$** and **$DK2\_PRICE_t$**: Represents the arithmetic mean price (€/MWh) for each day between January 1st of 2010 and December 31st of 2013, of the transactions in the Nord Pool Spot´s day-ahead auction (Elspot) for the area of West Denmark and East Denmark, respectively[1];
- **IRL_PRICE_t**: Represents the arithmetic mean price (€/MWh) for each day between January 1st, of 2010 and December 31st of 2013, of the transactions in the Single Electricity Market (SEM) day-ahead auction (EA1-ex-ante 1)[2];

[1] All the data for the Denmark prices was retrieved at 30/05/2014 from https://www.energinet.dk/EN/El/Engrosmarked/Udtraek-af-markedsdata/Sider/default.aspx. This is the website of the Transmission System Operator of Denmark, Energinet.

[2] The prices for each day were retrieved at 30/05/2014 from the website of SEMO (http://www.sem-o.com/marketdata/Pages/default.aspx);

- **PT_PRICE_t** and **SP_PRICE_t**: Represents the arithmetic mean price (€/MWh) for each day between January 1st of 2010 and December 31st of 2013, of the transactions in the Iberian Electricity Market (MIBEL) day-ahead auction, for Portugal and Spain, correspondingly[3].

In table 1 we can observe that all the mean prices are identical, except for the spot price in Ireland, that was superior more than 15€/MWh in mean. The maximum prices in Denmark reached very high values (even more than 500€/MWh in the west area).

The minimum prices are negative in Denmark. The Nord Pool Spot prices can be negative, what can happen if there is over-supply. In the other markets, that cannot happen. Because of that in Portugal and Spain the minimum price is 0€/MWh. Interestingly the minimum price in Ireland is 34,87€/MWh, only 5€ less than the average price in the west area of Denmark, which denotes the higher electricity prices in that country.

The spot prices in Portugal and Spain are very similar, with almost equal mean, standard deviation and equal maximum and minimum. In fact, the correlation coefficient between these two prices is 0,98. That indicates the integration of the countries in a single market. On the contrary, the prices in Denmark are different in mean, standard deviation and maximum. And their correlation coefficient is only 0,41. These results are somewhat strange, because they suggest that the market in Portugal and Spain is more integrated than the two areas of Denmark.

Table 1 - Descriptive statistics for the spot prices in the wholesale markets - sample period of January 2010 – December 2013

	Mean	Std. Dev.	Maximum	Minimum	Observations
DK1_PRICE	42,43 €	14,93 €	436,33 €	-38,43 €	1.461
DK2_PRICE	45,87 €	20,79 €	505,68 €	-38,38 €	1.461
IRL_PRICE	62,52 €	9,76 €	126,51 €	34,87 €	1.461
PT_PRICE	44,88 €	12,64 €	93,11 €	0,00 €	1.461
SP_PRICE	44,61 €	12,61 €	93,11 €	0,00 €	1.461

[3] This data was retrieved from The Iberian Energy Derivatives Exchange (OMIP) website (http://www.omip.pt/Downloads/SpotPrices/tabid/296/language/pt-PT/Default.aspx) at 03/06/2014.

4.1.2. COMMODITIES AND EMISSIONS PRICES

In our study we use data from other markets that can affect the electricity prices in the wholesale markets.

Several authors show the causal relation between the natural gas prices and the electricity prices (Emery and Liu, 2002; Nakajima and Hamori, 2013). And in studies similar to our own, other authors use the natural gas price as a variable to determine the electricity price (Woo *et al.*, 2011; Forrest and MacGill, 2013). This is indeed an important commodity regarding the generation of electricity. In 2010, almost one quarter (24%) of all the generation of electricity in the UE came from natural gas. In Ireland that percentage was 61,9% in the same year, and in Spain almost one third (32,2%) (European Commission, 2012).

Because of data availability we use the natural gas prices in the Gaspoint Nordic Spot (Denmark). This price is, therefore, only a proxy for the natural gas price in Ireland (for Portugal and Spain, the *brent* price is a better proxy, as we see below). However, the natural gas price in Denmark is a good proxy for the Ireland prices, given the growing integration of natural gas hubs in Europe (Neumann *et al.*, 2012, Gianfreda *et al.*, 2012).

Coal is a traditional fossil fuel for power generation and nowadays it still has an important position to secure electricity generation. In 2010, in Denmark almost half (43,75%) of the electricity was generated in combined heat and power (CHP) plants fueled by coal. In Portugal and Ireland, coal plants generated 13,13% and 14,46%, respectively, of the total electricity. Spain, that has coal mines, ironically, only generated 8,31% of electricity from coal plants (Eurostat, 2014). So, the price of coal is a significant part of the cost of coal plants and, therefore, a main determinant of electricity price.

Like Zachmann (2013) and Sensfuß *et al.* (2008), we use the coal price and also the CO_2 price as a determinant of the electricity price in the Europe. Because thermal plants need European Emission Allowances (EUA) to pollute, this price is a significant cost of coal and other fossil fuel plants too. As pointed out by Fell (2010), in a competitive market, the price of CO_2 emissions should be passed to the electricity price, and that is the case in the Nordic market.

Finally we use the *brent* price, for two different reasons. First, although in a small percentage, electricity is still generated in crude oil plants and in petroleum products plants. In 2010, Spain had 6% of its electricity generated by this type of plants. In Portugal, that value was 5,6%, in Denmark 2,4% and in Ireland 1,3% (European Commission (2012)).

The second reason is the price formation of natural gas in Europe. Oil-indexed long contracts of supply of natural gas represent a large part of the natural gas imported to Europe. That reality is now less common in North Europe, but in the Iberian Peninsula, that represents the majority of the imports of natural gas from Africa (Albrecht *et al.* (2014)). For these two reasons, directly or indirectly, the price of the *brent* crude oil could influence the price of electricity in Europe.

The energy and emissions prices variables that we use in our analysis are thus:

- **$BRENT_t$**: the daily spot price for the light crude oil know as *brent* (€/barrel), between January 1st of 2010 and December 31st of 2013. The value for each day refers to the closing price of that same say, or if the market was closed, of the immediately previous closing price[4];
- **$COAL_t$**: the daily spot price (€/tonne) for the thermal coal delivered (CIF) at the ARA (Amsterdam, Rotterdam, Antwerp) ports, between January 1st of 2010 and December 31st 2013. The value for each day refers to the closing price of that same say, or if the market was closed, of the immediately previous closing price[5];
- **EUA_t**: the daily spot price (€/tonne CO_2e) for the European Emission Allowances, between January 1st of 2010 and December 31st of 2013 in the secondary market. The value for each day refers to the closing price of that same say, or if the market was closed, of the immediately previous closing price[6];

[4] The data was retrieved from the U.S. Energy Information Administration (EIA) (http://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm accessed May 30, 2014).

[5] The data was retrieved from the Energy Market Price website (http://www.energymarketprice.com/ accessed June 07, 2014).

6 The data was retrieved from the SENDECO2 website (http://www.sendeco2.com/ accessed June 09, 2014).

- **NAT_GAS$_t$**: Represents the arithmetic mean price of natural gas (€/MWh) for each day between January 1st of of 2010 and December 31st of 2013, of the transactions in the Gaspoint Nordic Spot day-ahead market (Denmark)[7].

Table 2 - Descriptive statistics for the energy and emissions prices - sample period of January 2010 – December 2013

	Mean	Std. Dev.	Maximum	Minimum	Observations
BRENT	77,10 €	11,07 €	98,14 €	50,47 €	1.461
COAL	72,67 €	11,28 €	100,75 €	52,08 €	1.461
EUA	9,73 €	4,32 €	16,80 €	2,70 €	1.461
NAT_GAS	23,69 €	4,70 €	78,64 €	12,26 €	1.461

Analyzing the descriptive statistics in table 2, we could conclude that BRENT and COAL have similar variations. Their maximum prices are around 100€, and their minimum prices are similar too (50€ and 52€ respectively). Their standard deviation and mean are also identical. However, if we see their correlation coefficient (in table 3), there is a positive but weak one. Figure 17 illustrate this too.

NAT_GAS show the higher amplitude of all the commodity prices (minimum of 12,26€ and maximum of 78,64€), as we can see in figure 17. Nevertheless, this is influenced by a peak in the price at 22/03/2014. Otherwise its price varies between 12€ and 40€.

Table 3 - Correlation coefficient - energy and emissions prices - sample period of January 2010 – December 2013

Correlation	BRENT	COAL	EUA	NAT_GAS
BRENT	1,00			
COAL	0,16	1,00		
EUA	- 0,60	0,50	1,00	
NAT_GAS	0,63	- 0,01	- 0,62	1,00

[7] The data was retrieved from the Gaspoint Nordic website (http://www.gaspointnordic.com/market-data), accessed June 09, 2014.

EUA shows a completely different trend, as we can see in figure 17. In 2010 and in the beginning of 2011 it varies between 12€ and 16€. But after 2012 its price was tumbling until around 3€ in the end of the period in question.

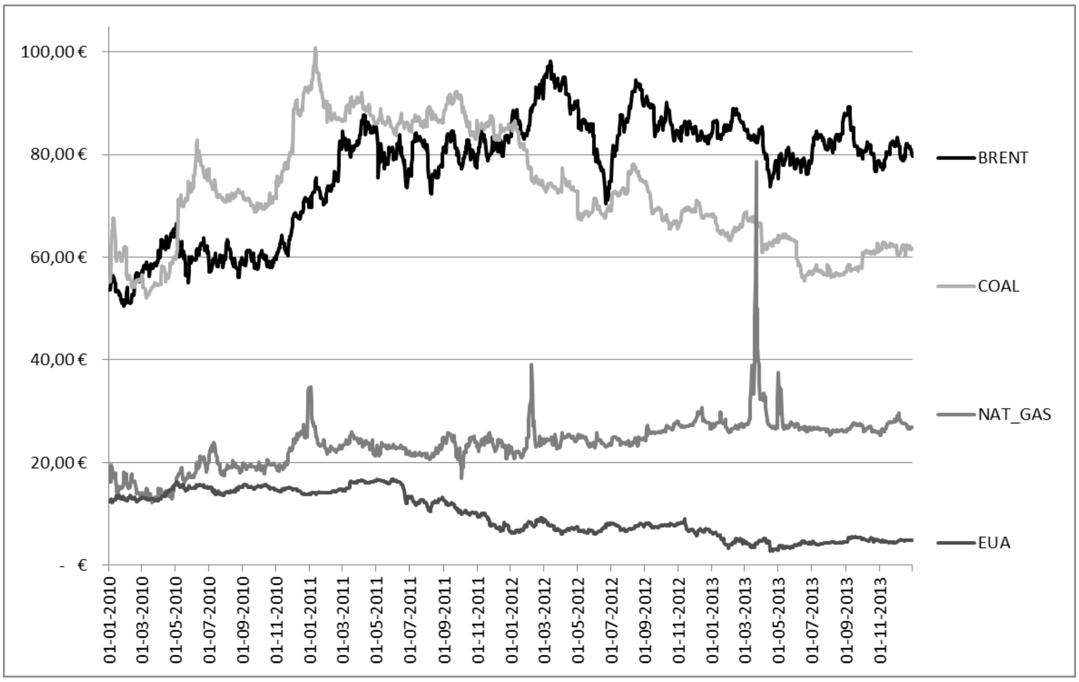


Figure 17 - Energy and emissions prices between January 2010 and December 2013

4.1.3. STOCK EXCHANGES INDEXES

In our analysis of the effect of wind power in the spot price of electricity we also use, as an independent variable, the value of the most notorious and liquid stock market index in each country. From the literature review performed, we found no studies that proceed in this way. However, we want to test here the hypothesis that a variation in the equity market could be transmitted to a *real* market, such the electricity wholesale market. For each country we use the most important index, as follows:

- **$OMXC20_t$**: OMX Copenhagen 20 Index - the market value weighted index of the 20 most traded shares in the Copenhagen Stock Exchange, for the period between January 1st of 2010 and December 31st of 2013. The index value for each day refers to the closing price of that same say, or if the market was closed, of the immediately previous closing value[8];
- **$ISEQ20_t$:** The market value weighted index of the 20 most traded shares in the Irish Stock Exchange (ISE), for the period between January 1st of 2010 and December 31st of 2013. The index value for each day refers to the closing price of that same say, or if the market was closed, of the immediately previous closing value[9];
- **$IBEX35_t$**: The market value weighted index of the 35 most traded shares in the 4 Spanish Stock Exchanges (BME), for the period between January 1st of 2010 and December 31st of 2013. The index value for each day refers to the closing price of that same say, or if the market was closed, of the immediately previous closing value[10];
- **$PSI20_t$**: The market value weighted index of the 20 most traded shares in the Portuguese Stock Exchange, for the period between January 1st, of 2010 and December 31st, 2013. The index value for each day refers to the closing price of that same say, or if the market was closed, of the immediately previous closing value[11].

[8] The data was retrieved from NASDAQ OMX website (http://www.nasdaqomxnordic.com/) at 02/09/2014.
[9] The data was retrieved from ISE website (http://www.ise.ie/) at 02/09/2014.
[10] The data was retrieved from http://www.eleconomista.es/ at 02/09/2014.
[11] The data was retrieved from http://www.bolsadelisboa.com.pt/ at 02/09/2014.

Table 4 - Descriptive statistics for the stock market indexes - sample period of January 2010 – December 2013

	Mean	Std. Dev.	Maximum	Minimum	Observations
OMXC20	458,48	68,78	615,50	335,10	1.461
ISEQ20	522,64	87,70	738,37	382,39	1.461
IBEX35	9.080,11	1.309,88	12.222,50	5.956,30	1.461
PSI20	6.434,44	1.070,36	8.839,75	4.408,73	1.461

The descriptive statistics of each index (table 4) cannot be compared because the indexes are very different in value. The OMXC20 have a maximum value of almost twice the minimum. If observed in figure 18, this index has the better performance compared with the others here analyzed, with the maximum value achieved in the last day of the period considered. The same happens with ISEQ20, the maximum value (738,37) was in 27/12/2013. Both indexes have more than 50% the value in the end of the period of what they had in the beginning.

The PSI20 and IBEX35 had similar evolutions since 2010. They show a negative growth and in the end of 2013, their value was around 80% of what was in the beginning of period. These two indexes show a high correlation coefficient (0,95). The same occurs with the ISEQ20 and OMXC20 (0,88). As expected seeing figure 18, IBEX35 and PSI20 have negative and weak correlations with ISEQ20 and OMXC20.

Figure 18 - Evolution of the stock exchanges indexes (100% = index at 01/01/2010)

4.1.4. ELECTRICITY GENERATION DATA

For the determination of the price of electricity in the wholesale markets we also use daily data of power generation for the 4 countries. Here we have to be very careful to choose variables that are exogenous to the bidding process output itself.

For the 4 countries we use the total system demand and the wind power generation. As explained in chapter 3, the system demand for electricity is an exogenous variable in the short term, because the end consumers do not receive the price signal of the wholesale markets (Sensfuß *et al.*, 2008; Sáenz de Miera *et al.*, 2008). Therefore, it could influence the price of electricity in the wholesale market, depending on the country electricity generation mix.

In studies similar to this, the authors use the system demand (or system load) as a variable to determine the electricity price (Woo et al., 201; Forrest and MacGill, 2013). They also use the wind power output that is the central independent variable in our analysis. Therefore, for each country, we use the daily system demand for electricity and also the daily wind power generation.

Spain is the only country of the 4 here analyzed that have nuclear power. Because of the characteristics of this power source, we include their daily generation output. We must focus that this is an exogenous variable given that its value only suffers reductions in case of necessity to proceed with maintenance or repair and has no correlation with the electricity price in the market. This variable was also used in Woo *et al.* (2011).

At least, we present here the data for the hydroelectric generation, both in Spain and Portugal. Denmark and Ireland have close to none hydroelectric capacity and generation (Eurostat, 2013). As pointed out by Woo *et al.* (2013) in hydro rich areas the impact of wind power generation could be lower. As presented below, this is a highly seasonal electric source and we found little correlation with the price in the wholesale market, both in Spain and Portugal.

We proceed with the presentation of the electricity generation data, first for Portugal and Spain, because they share the same wholesale market, and afterwards for Denmark and Ireland.

The electricity generation variables that we use for Spain and Portugal are[12]:

- **PT_DEMAND$_t$**: The system demand of electricity (MWh) for each day for the period between January 1st of 2010 and December 31st of 2013, in Portugal. The PT_Demand equals all the electricity generated plus the imports/exports balance;
- **PT_HIDRO$_t$**: The generation of hydroelectricity (MWh) for each day for the period between January 1st of 2010 and December 31st of 2013, in Portugal;
- **PT_WIND$_t$**: The generation of wind power (MWh) for each day for the period between January 1st of 2010 and December 31st of 2013, in Portugal;
- **SP_DEMAND$_t$**: This is the system demand of electricity (MWh) for each day for the period between January 1st of 2010 and December 31st of 2013, in Spain. The SP_Demand equals all the electricity generated plus the imports/exports balance;
- **SP_HIDRO$_t$:** The generation of hydroelectricity (MWh) for each day for the period between January 1st of 2010 and December 31st of 2013, in Spain;
- **SP_NUCLEAR$_t$:** The generation of nuclear power (MWh) for each day for the period between January 1st of 2010 and December 31st of 2013, in Spain;
- **SP_WIND$_t$:** The generation of wind power (MWh) for each day for the period between January 1st of 2010 and December 31st of 2013, in Spain.

Table 5 - Descriptive statistics for the electricity generation data for Portugal and Spain - sample period of January 2010 – December 2013

	Mean	Std. Dev.	Maximum	Minimum	Observations
PT_DEMAND	140.242	14.568	183.300	106.000	1.461
PT_HIDRO	33.606	21.911	102.800	3.700	1.461
PT_WIND	27.260	17.672	85.300	1.500	1.461
SP_DEMAND	694.436	73.906	903.000	514.000	1.461
SP_HIDRO	98.234	46.143	249.000	27.000	1.461
SP_NUCLEAR	162.913	19.769	196.000	86.000	1.461
SP_WIND	128.541	66.799	343.000	12.000	1.461

[12] The data presented here was retrieved from the websites of the Transmission System Operators (TSO) of Portugal (REN - http://www.centrodeinformacao.ren.pt/PT/Paginas/CIHomePage.aspx) and Spain (REE - http://www.ree.es/es/actividades/balance-diario).

The data for Portugal is also presented in figure 19. As we can observe, the wind power and hydroelectric generation have an elevated variance. PT_WIND had a minimum of only 1.500 MWh produced in one day and a maximum of 85.300 MWh. This is a highly instable form of electricity production. But the same can be said from hydroelectricity, with a minimum of 3.700 MWh and a maximum of 102.800 MWh. Like wind power, hydro energy also depends on an exogenous factor, rain. However, unlike wind power it is possible to store water to produce electricity in a more advantageous time, but this cannot be done with complete control. In figure 19, we can perceive that the end of 2011 and begging of 2012 were times of little rainfall, with lower hydroelectric production, compared to the other years. This translates the dependence of hydro power to an exogenous and uncontrollable factor.

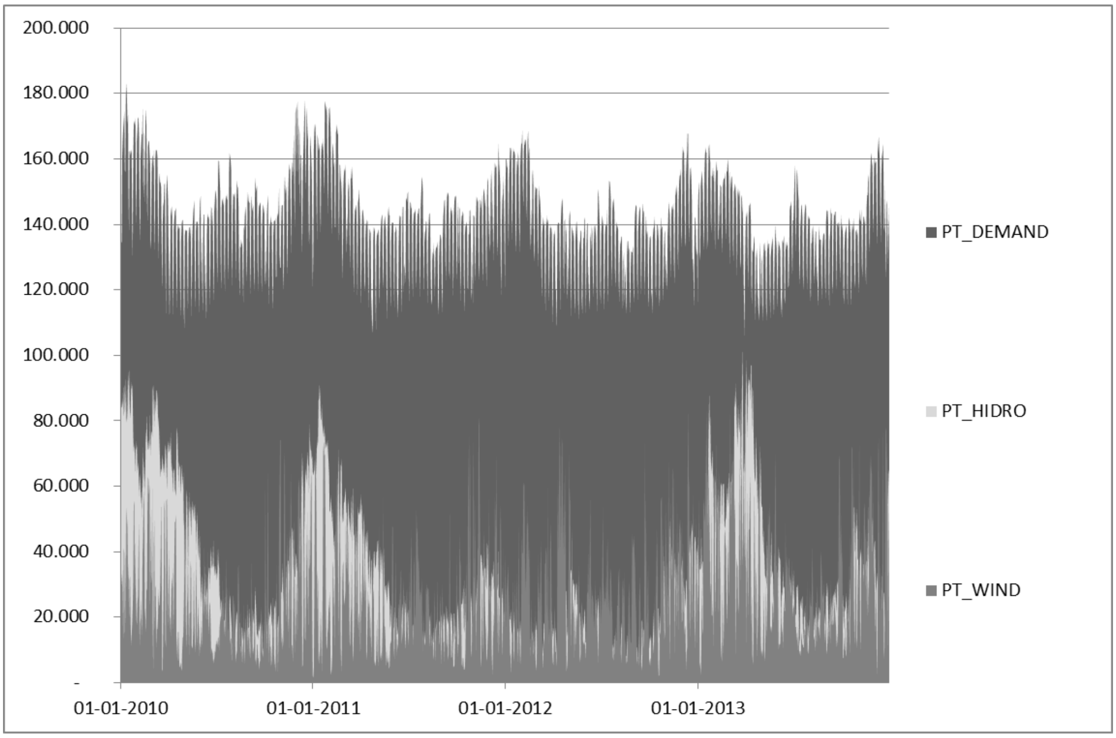


Figure 19 - Demand and wind and hydro generation in Portugal (MWh) between January, 2010 and December, 2013

The demand of electricity is very seasonal, as we can see in figure 19. In Portugal it varies between 106.000 MWh and 183.300MWh, with a mean of 140.242 MWh.

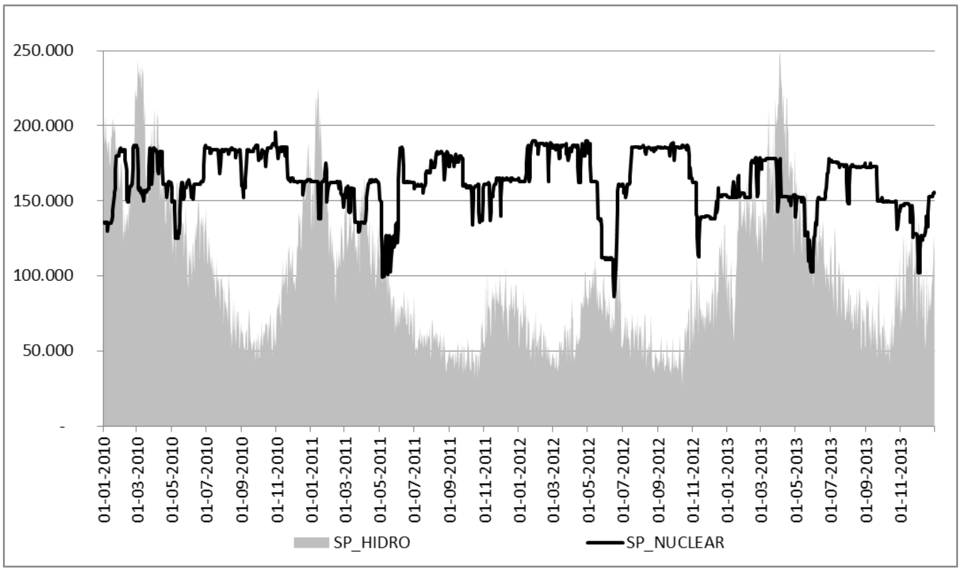


Figure 20 – Nuclear power and hydroelectricity (MWh) in Spain between January, 2010 and December, 2013

Unlike Portugal, Spain has nuclear stations to produce electricity. In figure 20 we can observe that this is a more stable energy in comparison with hydro energy. In peak situations, hydroelectricity can exceed the nuclear power production; however, in mean, nuclear output is more than 50% superior to hydroelectric production.

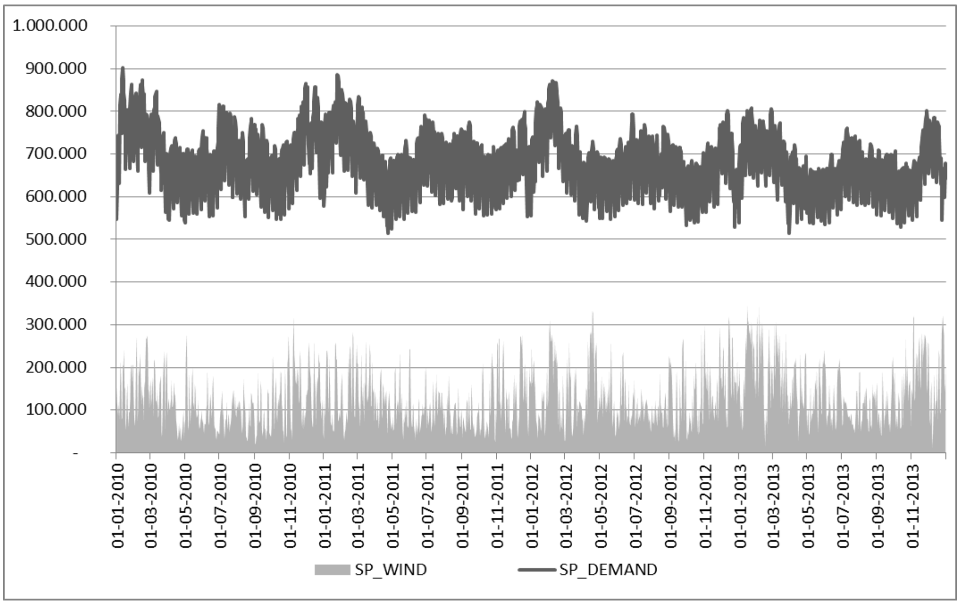


Figure 21 - System demand and wind power production (MWh) in Spain between January, 2010 and December, 2013

Wind power production in Spain is just as volatile as in Portugal, as it depends on meteorological conditions (the wind). Figure 21 show that variance compared with the demand. It is easy to discover that there is no correlation between these two variables, as we can find in table 6 (0,11).

Wind power production covered (in mean) each day around 19% of the system demand (that is almost equal to Portugal and Spain).

Table 6 - Correlation coefficients for the electricity data for Portugal and Spain - sample period of January 2010 – December 2013

Correlation	PT_DEMAND	PT_HIDRO	PT_WIND	SP_DEMAND	SP_HIDRO	SP_NUCLEAR	SP_WIND
PT_DEMAND	1,00						
PT_HIDRO	0,34	1,00					
PT_WIND	0,18	0,13	1,00				
SP_DEMAND	0,89	0,22	0,07	1,00			
SP_HIDRO	0,29	0,92	0,09	0,21	1,00		
SP_NUCLEAR	0,02	- 0,22	- 0,11	0,09	- 0,23	1,00	
SP_WIND	0,22	0,14	0,73	0,11	0,08	- 0,09	1,00

The higher correlation coefficients are between the demand in Portugal and Spain (0,89) and between hydro generation in Portugal and Spain (0,92). All the other coefficients are below 0,75. Other aspect we would like to highlight is the low correlation that the nuclear power has with the other variables. This displays the fact that nuclear power production is an exogenous factor, and varies in accordance with other factors, namely the necessity to proceed with maintenance or repair.

The electricity generation variables that we use for Denmark are[13]:

- **DK1_DEMAND$_t$**: The system demand of electricity (MWh) for each day for the period between January 1st of 2010 and December 31st of 2013, in east Denmark. The DK1_Demand equals all the electricity generated plus the imports/exports balance;
- **DK2_DEMAND$_t$**: The system demand of electricity (MWh) for each day for the period between January 1st of 2010 and December 31st of 2013, in west Denmark. The DK2_Demand equals all the electricity generated plus the imports/exports balance;

[13] The data presented for Denmark was retrieved from the website of the TSO of Denmark - Energinet (https://www.energinet.dk/EN/El/Engrosmarked/Udtraek-af-markedsdata/Sider/default.aspx) at 30/05/2014.

- **DK1_WIND$_t$**: The generation of wind power (MWh) for each day for the period between January 1st of 2010 and December 31st of 2013, in the west area of Denmark;
- **DK2_WIND$_t$**: The production of wind power (MWh) for each day for the period between January 1st of 2010 and December 31st of 2013, in the east area of Denmark.

Table 7 - Descriptive statistics for the electricity demand and wind power production in Denmark - sample period of January 2010 – December 2013

	Mean	Std. Dev.	Maximum	Minimum	Observations
DK1_DEMAND	56.344	7.643	74.553	37.967	1.461
DK2_DEMAND	37.966	5.225	53.587	27.252	1.461
DK1_WIND	20.067	14.588	77.079	192	1.461
DK2_WIND	6.617	5.161	20.918	18	1.461

Table 8 - Correlation coefficients for the electricity data for Denmark - sample period of January 2010 – December 2013

Correlation	DK1_DEMAND	DK2_DEMAND	DK1_WIND	DK2_WIND
DK1_DEMAND	1,00			
DK2_DEMAND	0,92	1,00		
DK1_WIND	0,14	0,17	1,00	
DK2_WIND	0,19	0,23	0,86	1,00

The West area of Denmark is the biggest and we can take this information from table 7, where the demand in DK1 is higher than the one in DK2 in all the descriptive stats. With the help of figure 22, we can easily conclude that the demand is highly seasonal. In winter, the demand is higher than in all the other seasons and that occurs in all the years in our sample.

As figure 22 shows and table 8 confirms there is a high correlation between the demand in the two areas of Denmark (0,92). Wind power generation, as it is expected, is highly volatile, as it happened in Portugal and Spain. Figure 23 illustrate what we can see in table 7 too. In DK1 the wind power generation had a minimum of 192 MWh and a maximum of 77.079 MWh. The maximum value is 400 times the minimum. In the east area that reality is even worse, with the maximum output in a day (20.918 MWh) representing more than 1000 times the minimum production of wind power (18 MWh).

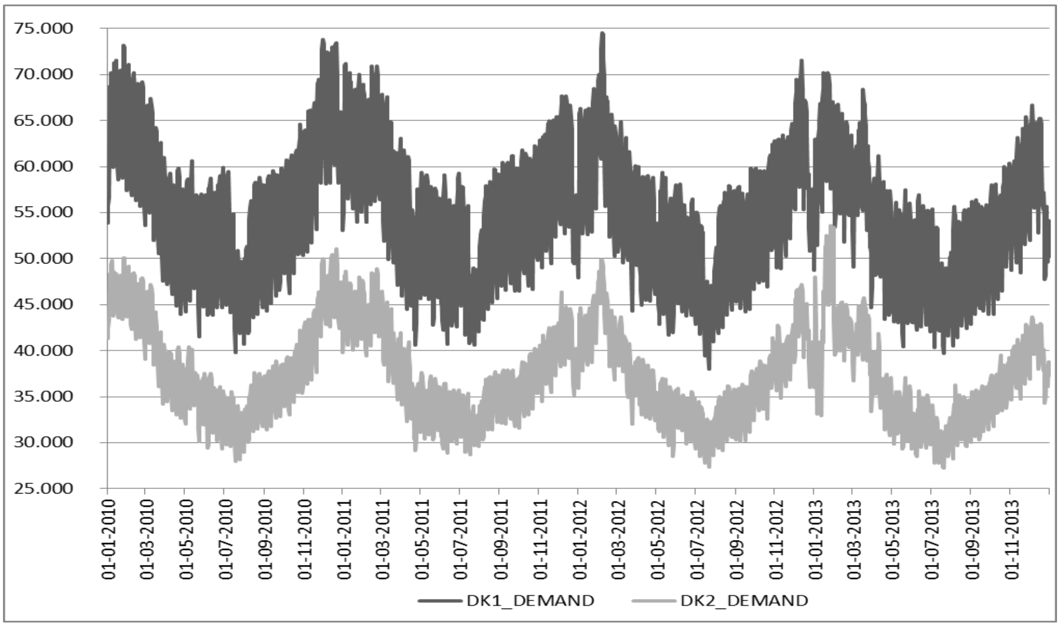


Figure 22 - System demand (MWh) in Denmark between January, 2010 and December, 2013

The wind power production in east Denmark is around 1/3 of the one in the West (in mean), whereas the demand in the east is 2/3 of the one in the area of the capital.
In mean, for each day, wind power production in Denmark covered 28% of the system demand.

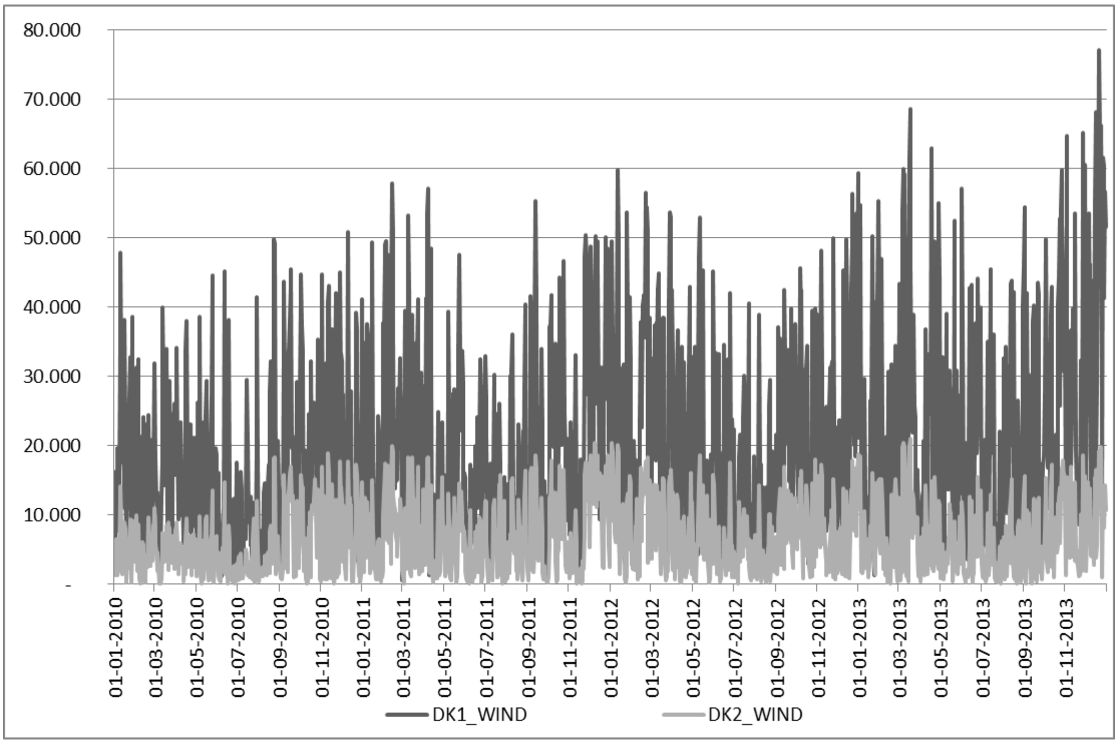


Figure 23 - Wind power production (MWh) in Denmark between January, 2010 and December, 2013

The electricity generation variables that we use for Ireland are[14]:

- **IRL_DEMAND$_t$**: The system demand of electricity (MWh) for each day for the period between January 1st of 2010 and December 31st of 2013, in Ireland. The IRL_Demand equals all the electricity generated plus the imports/exports balance;
- **IRL_WIND$_t$**: The production of wind power (MWh) for each day for the period between January 1st, of 2010 and December 31st, 2013 in Ireland.

Table 9 - Descriptive statistics for the electricity demand and wind power production in Ireland - sample period of January 2010 – December 2013

	Mean	Std. Dev.	Maximum	Minimum	Observations
IRL_DEMAND	284.225	30.654	382.879	219.525	1.461
IRL_WIND	42.729	30.376	131.624	2.197	1.461

Just like the wind power generation in Spain, Portugal and Denmark, in Ireland we can observe a high variance too. The maximum output in one day of wind power (131.624 MWh) is more than 90 times the minimum value (2.197 MWh). Other indicator of this is the standard deviation. This variance indicator is almost equal to the system demand and the wind power production (around 30.000 MWh). However the wind power represented only 15% of the demand (in mean).

The system demand is also seasonal as we see in the other countries, with more demand in the winter (see figure 24). Other aspect to focus is the difference between the maximum and minimum demand (more than 160.000 MWh).

As is easily seen in figure 24 and is proved in table 10, there is little correlation between wind power production and the system demand for electricity. This proves, again, that wind power is influenced by an exogenous factor (wind) and therefore cannot be fully controllable.

Table 10 - Correlation coefficients for the electricity data for Ireland - sample period of January 2010 – December 2013

Correlation	IRL_DEMAND	IRL_WIND
IRL_DEMAND	1,00	
IRL_WIND	0,13	1,00

[14] The data presented above was retrieved from the website of the Transmission System Operator (TSO) of Ireland - Eirgrid (http://www.eirgrid.com/operations/systemperformancedata/) at 30/05/2014.

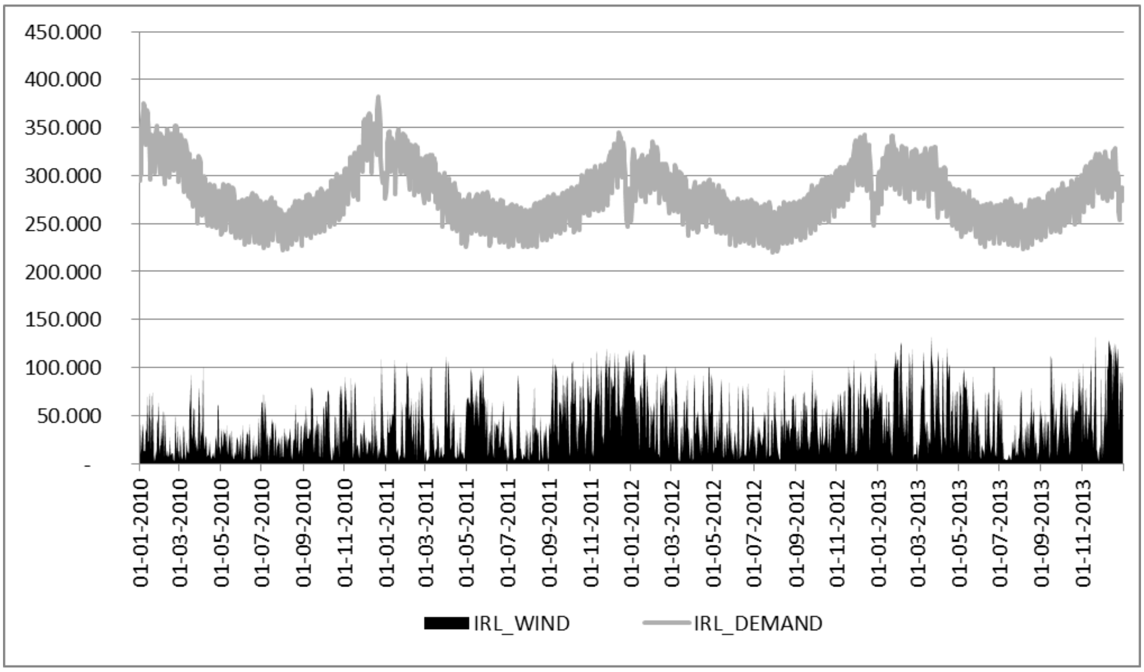


Figure 24 - Wind power generation and system demand (MWh) in Ireland between January, 2010 and December, 2013

Tables 11 and 12 show the correlation coefficients between the system demands and the wind power generations of the 4 countries.

We already show the results between the two areas of Denmark and between Portugal and Spain. However, we still can find strong correlations between the demands for electricity in relatively distant countries. For example between the Ireland demand and the demands for the two areas of Denmark, the correlation coefficients are close to 0,90.

Table 11 - Correlation coefficients for the system demand - sample period of January 2010 – December 2013

Correlation	DK1_DEMAND	DK2_DEMAND	IRL_DEMAND	PT_DEMAND	SP_DEMAND
DK1_DEMAND	1,00				
DK2_DEMAND	0,92	1,00			
IRL_DEMAND	0,89	0,91	1,00		
PT_DEMAND	0,83	0,76	0,81	1,00	
SP_DEMAND	0,75	0,65	0,69	0,89	1,00

The results for the wind generation correlation coefficients are completely different. If we do not consider the results between the two areas of Denmark (0,86) and between Portugal and Spain (0,73), there is no other strong correlations. These results show that the wind power generation is dependent on very specific weather conditions of each region/country.

Table 12 - Correlation coefficients for the wind power generation - sample period of January 2010 – December 2013

Correlation	DK1_WIND	DK2_WIND	IRL_WIND	PT_WIND	SP_WIND
DK1_WIND	1,00				
DK2_WIND	0,86	1,00			
IRL_WIND	0,25	0,20	1,00		
PT_WIND	0,06	0,02	0,06	1,00	
SP_WIND	0,07	0,07	0,05	0,73	1,00

4.2. MODEL

The objective of our study is to examine the reaction of the wholesale prices to the wind power generation. For that, we create a model to explain each of the 5 spot prices (introduced at 4.1.1.), so we have 5 models.

Since Portugal and Spain share the same market (MIBEL), the same variables are used in both models, with the exception of the stock index. Because of the high correlation values between the system demands and hydroelectricity generations of Portugal and Spain (that we observe in 4.1.4.), we combined these variables as follows:

- $IB\_DEMAND_t = PT\_DEMAND_t + SP\_DEMAND_t$;
- $IB\_HIDRO_t = PT\_HIDRO_t + SP\_HIDRO_t$.

For Denmark, because we have two prices, one for each market area (DK1 and DK2), we have two models with the same independent variables. Because of the high correlation values between the system demands and wind power generations of each market area of Denmark (see 4.1.4.), we combined these variables as follows:

- $DK\_DEMAND_t = DK1\_DEMAND_t + DK2\_DEMAND_t$;
- $DK\_WIND_t = DK1\_WIND_t + DK2\_WIND_t$.

For each model (and therefore to explain each spot price) we have the same set of independent variables: the commodities and emissions prices (*brent*, coal, natural gas and the price of the EUA); the stock index value (for each country we use the most liquid index as said in 4.1.2.); and the electricity generation data (the system demand and the wind power generation).

For Portugal and Spain models we use two more variables because of their differentiated generation mix. Both countries have important hydro power generation and Spain has nuclear power. Therefore these two variables were considered in their models. Note that, neither Denmark nor Ireland have nuclear power or considerable hydropower, as stated in 4.1.4.

The models we use are:

Portugal and Spain

1) $$PT\_PRICE = \beta_1 + \beta_2.BRENT_{t-2} + \beta_3.COAL_{t-2} + \beta_4.NAT\_GAS_{t-2} + \\ + \beta_5.EUA_{t-2} + \beta_6.ln(PSI20_{t-2}) + \beta_7.IB\_DEMAND_t + \\ + \beta_8.IB\_HIDRO_t + \beta_9.SP\_NUCLEAR_t + \\ + \beta_{10}.PT\_WIND_t + \beta_{11}.SP\_WIND_t + \beta_{12}.PT\_PRICE_{t-1} + \varepsilon$$

2) $$SP\_PRICE = \alpha_1 + \alpha_2.BRENT_{t-2} + \alpha_3.COAL_{t-2} + \alpha_4.NAT\_GAS_{t-2} + \\ + \alpha_5.EUA_{t-2} + \alpha_6.ln(IBEX35_{t-2}) + \alpha_7.IB\_DEMAND_t + \\ + \alpha_8.IB\_HIDRO_t + \alpha_9.SP\_NUCLEAR_t + \\ + \alpha_{10}.PT\_WIND_t + \alpha_{11}.SP\_WIND_t + \alpha_{12}.SP\_PRICE_{t-1} + \varepsilon$$

Denmark

3) $$DK1\_PRICE = \gamma_1 + \gamma_2.BRENT_{t-2} + \gamma_3.COAL_{t-2} + \gamma_4.NAT\_GAS_{t-2} + \\ + \gamma_5.EUA_{t-2} + \gamma_6.ln(OMXC20_{t-2}) + \gamma_7.DK\_DEMAND_t + \\ + \gamma_8.DK\_WIND_t + \gamma_9.DK1\_PRICE_{t-1} + \varepsilon$$

4) $$DK2\_PRICE = \delta_1 + \delta_2.BRENT_{t-2} + \delta_3.COAL_{t-2} + \delta_4.NAT\_GAS_{t-2} + \\ + \delta_5.EUA_{t-2} + \delta_6.ln(OMXC20_{t-2}) + \delta_7.DK\_DEMAND_t + \\ + \delta_8.DK\_WIND_t + \delta_9.DK2\_PRICE_{t-1} + \varepsilon$$

Ireland

5) $$IRL\_PRICE = \lambda_1 + \lambda_2.BRENT_{t-2} + \lambda_3.COAL_{t-2} + \lambda_4.NAT\_GAS_{t-2} + \\ + \lambda_5.EUA_{t-2} + \lambda_6.ln(ISEQ20_{t-2}) + \lambda_7.IRL\_DEMAND_t + \\ + \lambda_8.IRL\_WIND_t + \lambda_9.IRL\_PRICE_{t-1} + \varepsilon$$

As Forrest and MacGill (2013) discuss, the logarithmic transformation of the price data should provide the best fit. However, given the fact that the prices in Denmark are, in some days, negative, and in Portugal and Spain, there are some days when the electricity price is 0€/MWh, we cannot proceed by this way. The same problem appeared in Woo *et al.* (2011).

We could only do the logarithmic transformation of the price for Ireland, but, due to the purpose of comparability, we choose similar models for each price/country.

The prices of the commodities (*brent*, coal and natural gas) and of the CO_2 emissions and the stock indexes are lagged two days in ours models. We do this because when the producers are bidding (the day before of the delivery of electricity (-1)) they only have the knowledge of the closing values of the day before that (-2).

As stated in 4.1.1., the price of the commodities and the emissions are an important cost to the electricity generation plants. We anticipate that a rising of these costs should increase the wholesale prices of electricity, so we expect a positive value for their coefficients. We must, however, see different results for each country depending on their electricity generation mix.

We want to test the hypothesis of a direct effect of the stock market on the electricity wholesale market. For this reason, we use the most notorious and liquid index in each country. These are the only independent variables that are in the natural logarithm form. This is so because we want to observe the outcome of relative changes in the stock markets in the electricity prices. We theorize that a positive variation in the stock market could have a small but positive impact in the wholesale electricity price.
A higher demand for electricity in a certain day creates the necessity for more electricity generation and therefore the entrance in the market of more costly plants (Woo *et al.*, 2011; Forrest and MacGill, 2013; Sensfuß *et al.*, 2008). Therefore, we expect a positive coefficient associated with the system demand for each country.

The key independent variables to our study are the wind power generations (PT_WIND; SP_WIND; DK_WIND; IRL_WIND). We expect that a higher wind generation should cause a negative effect on the electricity prices in the wholesale market, due to the merit order effect discussed in chapter 3.

There is one autoregressive term (PT_PRICE_{t-1}; SP_PRICE_{t-1}; $DK1\_PRICE_{t-1}$; $DK2\_PRICE_{t-1}$; IRL_PRICE_{t-1}) in each equation. Like other authors pointed out (Woo *et al.*, 2011; 2013; Forrest and MacGill, 2013), the price of one period is likely to influence the posterior one. With the inclusion of the lagged prices (in one day) we want to test that possibility.

As referred, because of the differentiated generation mix in Portugal and Spain, we include two more variables for the generation of nuclear power and hydropower. Regarding the nuclear output, we anticipate that a reduction in its generation could increase the price in the wholesale market. This a base load plant with low marginal cost (Woo *et al.*, 2011) and if its output decreases, this creates an opportunity for other electricity plants with higher costs to enter the market.

We include the hydroelectric production in Portugal and Spain because its value is dependent on exogenous conditions (rainfall) and is very seasonal (see figure 19 and 20). Although, this is a dispatchable generation (because the rain could be stored in the dams), this cannot be done with complete control and is dependable on legal minimums and maximums and meteorological conditions. Like the nuclear generation, this is a base load plant (Woo *et al.*, 2013; European Commission, 2012). Therefore we expect that a rise in hydroelectric generation creates a downward effect on the wholesale price of electricity.

5. RESULTS

Tables 13 to 17 show the regressions results applying the models 1-5 to the data presented in 4.1. The estimations were obtained using the Ordinary Least Square (OLS) method.

Table 13 - Regression results of Model 1, obtained by applying the OLS method with the Newey-West standard errors (* - statistically significant at the 1% level/ ** - 5% level / * - 10% level)**

Dependent Variable	PT_PRICE			
	COEFFICENT			STD. ERROR
CONSTANT	β1	-88,015410	*	20,138500
BRENT(-2)	β2	0,107049	*	0,027565
COAL(-2)	β3	0,092995	*	0,029953
NAT_GAS	β4	0,040483		0,093499
EUA(-2)	β5	-0,520707	*	0,127083
ln(PSI20(-2))	β6	11,350430	*	2,381468
IB_DEMAND	β7	0,000040	*	0,000003
IB_HIDRO	β8	-0,000061	*	0,000006
SP_NUCLEAR	β9	-0,000095	*	0,000012
PT_WIND	β10	-0,000127	*	0,000016
SP_WIND	β11	-0,000041	*	0,000005
PT_PRICE(-1)	β12	0,478309	*	0,043080
R^2	0,844648			

Table 14 - Regression results of Model 2, obtained by applying the OLS method with the Newey-West standard errors (* - statistically significant at the 1% level/ ** - 5% level / * - 10% level)**

Dependent Variable	SP_PRICE			
	COEFFICENT			STD. ERROR
CONSTANT	α1	-83,890690	*	18,295510
BRENT(-2)	α2	0,100900	*	0,029862
COAL(-2)	α3	0,099960	*	0,032912
NAT_GAS	α4	0,092050		0,114675
EUA(-2)	α5	-0,492201	*	0,123855
ln(IBEX35(-2))	α6	10,261170	*	2,048992
IB_DEMAND	α7	0,000042	*	0,000003
IB_HIDRO	α8	-0,000054	*	0,000005
SP_NUCLEAR	α9	-0,000099	*	0,000012
PT_WIND	α10	-0,000107	*	0,000016
SP_WIND	α11	-0,000052	*	0,000005
SP_PRICE(-1)	α12	0,450146	*	0,043531
R^2	0,818037			

Table 15 - Regression results of Model 3, obtained by applying the OLS method with the Newey-West standard errors (* - statistically significant at the 1% level/ ** - 5% level / * - 10% level)**

Dependent Variable		DK1_PRICE		
		COEFFICENT		STD. ERROR
CONSTANT	γ1	-85,655890	*	19,559250
BRENT(-2)	γ2	-0,046192		0,058873
COAL(-2)	γ3	0,095584	**	0,047792
NAT_GAS	γ4	0,361061	**	0,141496
EUA(-2)	γ5	0,984437	*	0,160435
ln(OMXC20(-2))	γ6	12,159780	*	3,713473
DK_DEMAND	γ7	0,000328	*	0,000026
DK_WIND	γ8	-0,000257	*	0,000029
DK1_PRICE(-1)	γ9	0,190332	**	0,083213
R^2		0,359429		

Table 16 - Regression results of Model 4, obtained by applying the OLS method with the Newey-West standard errors (* - statistically significant at the 1% level/ ** - 5% level / * - 10% level)**

Dependent Variable		DK2_PRICE		
		COEFFICENT		STD. ERROR
CONSTANT	δ1	-8,760769		38,794640
BRENT(-2)	δ2	-0,116090	***	0,067579
COAL(-2)	δ3	-0,049161		0,112543
NAT_GAS	δ4	0,255882	**	0,129044
EUA(-2)	δ5	0,766986	*	0,187656
ln(OMXC20(-2))	δ6	-0,563126		6,080929
DK_DEMAND	δ7	0,000496	*	0,000077
DK_WIND	δ8	-0,000238	*	0,000022
DK2_PRICE(-1)	δ9	0,362509	*	0,054742
R^2		0,436833		

As can be seen, all the regressions for the 5 models present a lagged price that is statistically significant (at least at a 5% significance level). This is an indication for the presence of a first-order autoregressive process (AR(1)). This means that the level of prices in one certain day will have an impact in the price of the followings days. Because of these findings, the coefficients of the others independent variables cannot be read directly. Therefore we will present new regressions with the use of the non-linear least squares (NLS) method with an AR(1) process to overcome this problem. The lagged prices are replace by an AR(1) term. The new regressions are in tables 18-22.

Table 15 - Regression results of Model 5, obtained by applying the OLS method with the Newey-West standard errors (* - statistically significant at the 1% level/ ** - 5% level / * - 10% level)**

Dependent Variable		**IRL_PRICE**		
		COEFFICENT		STD. ERROR
CONSTANT	λ1	-35,071630	***	19,356630
BRENT(-2)	λ2	0,144222	*	0,032280
COAL(-2)	λ3	0,055818		0,043064
NAT_GAS	λ4	0,789043	*	0,118074
EUA(-2)	λ5	0,160326	***	0,096643
ln(ISEQ20(-2))	λ6	5,101660	***	2,856968
IRL_DEMAND	λ7	0,000055	*	0,000007
IRL_WIND	λ8	-0,000028	*	0,000007
IRL_PRICE(-1)	λ9	0,256044	*	0,038904
R^2		0,503966		

Table 16 - Regression results of Model 1 with an AR(1), obtained by applying the NLS method with the Newey-West standard errors (* - statistically significant at the 1% level/ ** - 5% level / * - 10% level)**

Dependent Variable		**PT_PRICE**		
		COEFFICENT		STD. ERROR
CONSTANT	β1	-26,611210		39,465210
BRENT(-2)	β2	0,198458	*	0,056002
COAL(-2)	β3	0,224831	*	0,059241
NAT_GAS	β4	-0,037028		0,171408
EUA(-2)	β5	-0,574810	**	0,262477
ln(PSI20(-2))	β6	4,888750		4,624566
IB_DEMAND	β7	0,000049	*	0,000003
IB_HIDRO	β8	-0,000064	*	0,000009
SP_NUCLEAR	β9	-0,000097	*	0,000018
PT_WIND	β10	-0,000115	*	0,000013
SP_WIND	β11	-0,000073	*	0,000005
AR(1)	β12	0,787072	*	0,037840
R^2		0,880712		

Table 17 - Regression results of Model 2 with an AR(1), obtained by applying the NLS method with the Newey-West standard errors (* - statistically significant at the 1% level/ ** - 5% level / * - 10% level)**

Dependent Variable	SP_PRICE			
	COEFFICENT			STD. ERROR
CONSTANT	α1	-99,237640	*	35,376920
BRENT(-2)	α2	0,177114	*	0,052152
COAL(-2)	α3	0,248753	*	0,057638
NAT_GAS	α4	-0,027249		0,221465
EUA(-2)	α5	-0,892850	*	0,244950
ln(IBEX35(-2))	α6	13,167190	*	4,026719
IB_DEMAND	α7	0,000052	*	0,000003
IB_HIDRO	α8	-0,000072	*	0,000008
SP_NUCLEAR	α9	-0,000111	*	0,000019
PT_WIND	α10	-0,000090	*	0,000013
SP_WIND	α11	-0,000089	*	0,000005
AR(1)	α12	0,726125	*	0,041625
R^2		0,857295		

Table 18 - Regression results of Model 3 with an AR(1), obtained by applying the NLS method with the Newey-West standard errors (* - statistically significant at the 1% level/ ** - 5% level / * - 10% level)**

Dependent Variable	DK1_PRICE			
	COEFFICENT			STD. ERROR
CONSTANT	γ1	-99,690320	*	22,622390
BRENT(-2)	γ2	-0,050363		0,066894
COAL(-2)	γ3	0,101168	***	0,056758
NAT_GAS	γ4	0,465353	*	0,172364
EUA(-2)	γ5	1,277986	*	0,209785
ln(OMXC20(-2))	γ6	14,032330	*	4,228365
DK_DEMAND	γ7	0,000389	*	0,000032
DK_WIND	γ8	-0,000273	*	0,000021
AR(1)	γ9	0,212681	***	0,116091
R^2		0,359429		

Table 19 - Regression results of Model 4 with an AR(1), obtained by applying the NLS method with the Newey-West standard errors (* - statistically significant at the 1% level/ ** - 5% level / * - 10% level)**

Dependent Variable	DK2_PRICE			
	COEFFICENT			STD. ERROR
CONSTANT	δ1	6,579660		60,087840
BRENT(-2)	δ2	-0,204387	***	0,110648
COAL(-2)	δ3	-0,077745		0,174791
NAT_GAS	δ4	0,444324	**	0,206719
EUA(-2)	δ5	1,255574	*	0,251573
ln(OMXC20(-2))	δ6	-3,175549		9,402222
DK_DEMAND	δ7	0,000682	*	0,000087
DK_WIND	δ8	-0,000261	*	0,000019
AR(1)	δ9	0,405881	*	0,073727
R^2	0,446588			

Table 20 - Regression results of Model 5 with an AR(1), obtained by applying the NLS method with the Newey-West standard errors (* - statistically significant at the 1% level/ ** - 5% level / * - 10% level)**

Dependent Variable	IRL_PRICE			
	COEFFICENT			STD. ERROR
CONSTANT	λ1	-62,844710	**	28,143730
BRENT(-2)	λ2	0,201349	*	0,041645
COAL(-2)	λ3	0,109242	**	0,061857
NAT_GAS	λ4	0,940552	*	0,141602
EUA(-2)	λ5	0,149321		0,129235
ln(ISEQ20(-2))	λ6	9,072708	**	4,193082
IRL_DEMAND	λ7	0,000082	*	0,000008
IRL_WIND	λ8	-0,000044	*	0,000007
AR(1)	λ9	0,298866	*	0,034449
R^2	0,51458			

Regarding these last regressions (tables 18 to 22), some independent variables are not statistically significant (considering at least a 10% significance level). We find, however, that removing them from the regressions does not significantly alter the results of the other variables. Therefore, we proceed with our analysis considering the results from these last adjustments (tables 18 to 22).

The coefficient of determination (R^2 – a indicator of the adjustment quality) is greater than 0,85 in Portugal and Spain. This means that more than 85% of the variance of the price of electricity in these two countries can be explained by the independent variables that we choose.

In Ireland the R^2 is slightly higher than 0,50. And in Denmark the adjust is better for the price in the east zone (0,45), than for the west price (0,36). This means that the independent variables that we choose for Denmark explain 45% of the variance of the price of electricity in the east area, and 36% of the variance of the price in the area.
These last results are compared with what we found in similar studies (Woo *et al.* (2011)).

For these results, we have to take into account that we have a large sample of 1459 observations (because of the lagged prices we lose 2 observations). Second, Spain and Portugal are a closed wholesale market, with little connection with France, so by having the variables for the two countries was enough to achieve a superior adjustment. The exact opposite happens with Denmark, which participates in the Nord Pool wholesale market. So, its domestic conditions only limitedly can set the price. And the adjustment quality difference between the two market areas of Denmark can easily be explained by the more openness of the west area to the market, than the east area, that have less grid connection with the neighbors market. Ireland also has a common market with Northern Ireland, and its market conditions were not taken into account in our study.

Third, the models for Portugal and Spain have two more variables (nuclear and hydro generation), and that can also explains its higher R^2.
The coefficient for the autoregressive term is higher in Portugal (0,78) and Spain (0,73) than in the other countries. This means that the price level of one day will affect the following ones, due to market conditions and other variables that are not in our models. The higher values in the Iberian Peninsula suggest that this market is slower to adjust and adapt than the others here analyzed.

The oil price (*brent*) is only statistically significant (considering at least a 5% significance level) in the regressions for Portugal, Spain and Ireland. The coefficient value for these adjustments are similar (around 0,20). This means that an increase of

1€/barrel of *brent* will affect positively the price of electricity in these wholesale markets, in around 0,20€/MWh. In Denmark the price of *brent* did not had a significant effect on the wholesale price of electricity.

Like the price of *brent,* the coal price is only statistically significant (considering at least a 5% significance level) in the regressions for Portugal, Spain and Ireland. The rising of the coal price in 1€/tonne should impact the price in the wholesale market of Portugal and Spain in more than 0,20€/MWh. In Ireland that impact is smaller, around 0,10€/MWh. This suggests that the coal plants in the Iberian Peninsula set the marginal price of the wholesale market more often than in Ireland.

Interestingly, the coal price is not statistically significant (considering at least a 5% significance level) for the price in Denmark, the country that relies more on coal to generate electricity of these 4 considered (43,75% in 2010 as we see in chapter 4.1.2).
The natural gas price is not a statistically significant variable for the adjustments in Portugal and Spain. However, it is statistically significant (considering at least a 5% significance level) for Denmark and Ireland.

For Portugal and Spain the supply of natural gas comes from Africa (Gouveia *et al.* (2014)), and the majority of imports are realized through long-term contracts, with the price depending on the price of *brent* (European Commission, 2012). Therefore, for the natural gas fired plants in Portugal and Spain, the price of the natural gas in the spot markets in Europe does not affect their costs, but the *brent* price does. Because of that we find (above) that the *brent* price is, indeed, a statistically significant variable for the determination of the wholesale prices in Portugal and Spain.

In Ireland and Denmark the increase of the natural gas price has a positive effect on the wholesale price of electricity. In Denmark an increase of the natural gas price of 1€/MWh would have increased the electricity price in around 0,45€/MWh. In Ireland the effect is stronger, with the same variation of the natural gas price causing a rise in the electricity price of 0,94€/MWh. This suggests that the natural gas plants set the marginal price more often in Ireland than in Denmark.

Regarding Ireland, with these results, we could argue that the high dependency on natural gas to generate electricity exposes them greatly to a price risk and security of supply. The costs of a shortage of supply are even studied by Leahy *et al.* (2012), given that more than 50% of electricity is generated by natural gas plants. We can also conclude, based on the regression results in table 22, that the pricing of natural gas in Ireland is both oil-indexed and decided in the wholesale market, because the *brent* price and the natural gas price in the spot market are both statistically significant variables (at a 1% significance level). This should be the case, as pointed out by the European Commission (2012).

The influence of the natural gas prices on the electricity prices is in accordance of what was found by other authors in similar studies (Woo *et al.*, 2011; 2013).

The price of the European emission allowances have different impacts in the wholesale markets here considered. In Portugal and Spain an increase in the emissions price causes a negative impact in the electricity price. In Denmark, the effect is the contrary, with the growth in the price of emissions allowances causing an increase in the wholesale prices. In Ireland this variable is not statistically significant. These results suggest that in Denmark the emissions allowances are a cost to the thermal plants, where in Portugal and Spain, they represent a gain. As Fell (2010) concludes, in the Nordic countries the CO_2 emission price is pass-through to the electricity price. That is the same conclusion we find for Denmark. For Portugal and Spain, these results suggest that the producers use their emissions allowances as a financial gain.

As stated in 4.2., we anticipated that a rise in the prices of the commodities and of the emission allowances should increase the wholesale prices of electricity. So we expected a positive value for their coefficients, as is the case in general. The different results for each country are the outcome of diverse electricity generation mixes.

The stock market indexes considered for each country had various results. The PSI-20 index (Portugal) is not a statistically significant variable for the adjustment for the price in Portugal. However the IBEX-35 is a statistically significant variable (at a 1% significance level) in the regression for the price of electricity in Spain.

In Denmark, the OMXC-20 is only determinant (i.e., statistically significant) for the price in the west area. In Ireland the ISEQ-20 is also statistically significant (at a 5% significance level).

These results show some level of dependency between the stock markets and the wholesale markets of electricity. For example, an increase of 1% in the IBEX-35, would cause a rise in the wholesale price of Spain of 0,13€/MWh. Denmark shows similar effect in the West area.

In 4.2., we anticipated that a positive variation in the stock market could have a small but positive impact in the wholesale electricity price, and that was the case in 3 of the 5 adjustments.

The demand of electricity is statistically significant in all the adjustments (at a 1% significance level). This is an expected outcome as we stated in 4.2., since all the coefficients are positive. This translates that a rise in the demand for electricity causes an increase in the price of electricity, due to the need of the entrance in the market of more costly plants. These results are similar to those found by other authors in similar analysis (Woo *et al.*, 2011;2013; Forrest and MacGill, 2013).

In Portugal and Spain, the increase of 1000 MWh in the demand would have increased the wholesale price of both countries in around 0,05€/MWh. In Denmark that effect is stronger. A rise in the demand of 1000MWh cause an increase in around 0,39€/MWh in the DK1 price and in around 0,62€/MWh in the DK2 price. In Ireland the result is similar to those of Portugal and Spain. The rise in the demand of 1000MWh, cause an increase in the IRL_Price, of around 0,082€/MWh.

Regarding only Portugal and Spain, the coefficients of the hydroelectric and nuclear productions are negative, as expected (see 4.2.). This means that an increase in the production of these two technologies create a downward impact on the wholesale market price. The effect of the nuclear production is stronger, suggesting that a decrease of the nuclear plants output have a very significant and positive effect on the spot price of electricity. This result is similar to the one found by Woo *et al.* (2011) for Texas.

Finally, regarding the primary objective of this study, which is the effect of wind energy in the wholesale price of electricity? Concerning this, all the coefficients in association with wind energy in all the regressions are statistically significant (at a 1% significance level) and have a negative signal. This means that, in all the markets here considered, the rise in the output of wind energy create a decline in the price of electricity, as we expected, due to the merit order effect discussed in chapter 3.

This downward effect per MWh is stronger in the markets of higher wind energy penetration (Denmark) that in other markets (Ireland). Therefore a rise in wind energy output of 1000 MWh in Denmark create a negative impact in the electricity price of around 0,27€/MWh. That effect is 0,04€/MWh in Ireland.

In Portugal, the Portuguese wind power output has a stronger effect on the spot price than the Spanish wind power output, per MWh. That does not happen in Spain, where the effect is similar (a negative impact of 0,09€/MWh per increase of 1000 MWh of wind power output). This can be explained by the difference in the market areas and demands. The demand in Portugal represents, in average, around 20% of the demand in Spain. Therefore, the interconnection capacity can sustain the transmission of electricity from Portugal to Spain, when Portugal has high wind output. However, the contrary is not the case. In times of high wind power output in Spain, the effect in the Portuguese spot price is limited by the interconnection capacity.

Table 21 - Estimates for the total change in the average price of electricity due to wind generation

	PT_PRICE	SP_PRICE	DK1_PRICE	DK2_PRICE	IRL_PRICE
€/MWh	- 12,54 €	- 13,85 €	- 7,28 €	- 6,96 €	- 1,87 €

Table 23 shows the estimates for the total change in the average price of electricity in the wholesale market due to wind generation. For the change in the prices of Portugal and Spain, both wind generation were included. The wind generation in Portugal contributed to the decrease of the spot price in around 25% for the PT_Price and around 18% for the SP_Price.

The results in table 23 are very different. In Ireland, wind generation had a small impact on the electricity price. Of the 4 countries, Ireland was the one with less wind power penetration on the electricity market. In the 4 years considered, the wind generation represented 15% of the system demand. In a country where natural gas dominates the electricity generation mix (see 4.1.2.) with more than 50% of all electricity generated in gas power plants, this low penetration of wind power is less effective in reducing the spot price.

The results for the two prices in Denmark are similar. The wind power generation contributed to decrease the electricity price in the wholesale market in around 7€/MWh. This is the difference between a scenario with 0 wind energy and the current average wind generation in Denmark. Even though Denmark is the country with more wind penetration in Europe (and therefore in the 4 countries here considered), their effect is smaller than those we found in Portugal and Spain. These results are affected by the electricity generation mix and by the integration of Denmark in a large market with more countries (the Nord Pool Spot). Denmark relies heavily on coal to produce electricity (in CHP plants), and of the 4 countries here analyzed, the one that relies less in natural gas (20% in 2010 and 13% in 2012 (Eurostat, 2014)). Because of the integration in the Nordic electric system, their domestic conditions can only limitedly set their own price. Therefore, wind generation does not have the same strong impact in Denmark that have in the Iberian Peninsula. However, we still have to highlight the fact that, the price of electricity in the wholesale market in Denmark is similar in average to the one in Portugal and Spain.

The impact of the wind generation in Portugal and Spain is around 13€/MWh. This is the difference between a scenario with 0 wind energy and the current average wind generation in both countries. The contribution of each country is similar to their share of combined market.

These results for the change in the price due to wind generation are similar to those found by other authors. Forrest and MacGill (2013) found that wind power decrease in 2,73$/MWh the spot price in the South Australia region, and reduced in 8,05$/MWh the spot price in the Victoria region of Australia, between 2009 and 2011. Weigt (2009) found that wind power reduced the spot price in Germany in around 10€/MWh, between 2006 and 2008. Sensfuß *et al.* (2008) calculated the effect of all RES in the spot price of electricity in Germany, in around 7,8€/MWh for 2006.

6. CONCLUSIONS AND POLICY IMPLICATIONS

The purpose of this study is to find the effect of the wind power generation on the wholesale price of electricity. For that, we develop a multiple linear regression model for each spot price of electricity in the wholesale markets of Denmark (Nord Pool), Portugal and Spain (MIBEL) and Ireland (SEM), the countries in the EU that have a higher penetration of wind power in the electricity market, in 2012. With daily data for four years (2010, 2011, 2012 and 2013), we find that, indeed, wind power generation reduces the wholesale price of electric energy. However, and contrary to the general notion, more wind power penetration does not necessary indicate a greater effect on the spot price of electricity. We find that the total effect of the wind power generation on the electricity price depends on the electricity generation mix of the country and on its integration with other markets.

For these reasons, we find that Ireland barely benefits from the decrease of the wholesale electricity price caused by the wind generation, because of its high dependency on natural gas to generate electricity. This also contributes to its higher price of electricity in the wholesale market. In Denmark, for instance, because of its integration in the Nord Pool Spot market wind power has lower capacity to influence the price. Portugal and Spain are the countries with the higher impact of wind generation in the wholesale price, around 13€/MWh in average. We also conclude that hydro and nuclear power reduce the electricity spot prices in Portugal and Spain.

The results show that policymakers should take into account not only the reality of their own country, but also the reality of the other markets where they are integrated. This highlights the need of integrated European policies and transversal decision procedure. The creation of an European electricity market should rely on this basis.

Additionally, an increase of wind power and other RES should consider the electricity generation mix that already exists and the features of the wholesale market.

Future research should be conducted for Denmark and Ireland, incorporating other data from the wholesale markets where they are integrated (Nord Pool Spot and SEM), that we could not collect in due time. For Portugal and Spain, it should be study if the total effect of the decrease in the market price compensates the total subsidies that were given to this RES.

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